West Virginia
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Total Bid: $0.00

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Responded By User ID: cgegenheimer

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Purchasing Division
2019 Washington Street East
Post Office Box 50130
Charleston, WV 25305-0130

State of West Virginia
Solicitation Response

Proc Folder:	1954879
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Solicitation Closes	Solicitation Response	Version
2026-05-06 13:30	SR 0926 ESR05062600000007647	1

VENDOR
VS0000052058
Bates White

Solicitation Number: CEOI 0926 PSC2600000002

Total Bid: 0 **Response Date:** 2026-05-06 **Response Time:** 12:20:30

Comments:

FOR INFORMATION CONTACT THE BUYER
Larry D McDonnell
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Vendor
Signature X **FEIN#** **DATE**

All offers subject to all terms and conditions contained in this solicitation

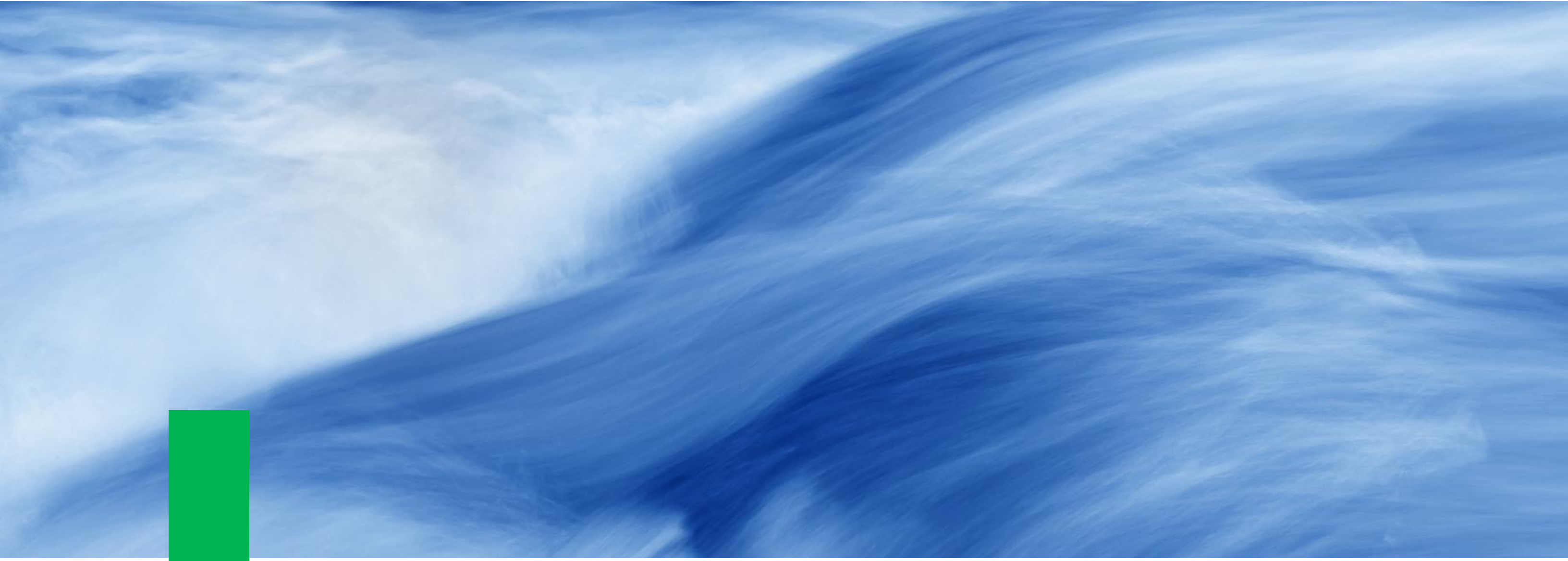
Line	Comm Ln Desc	Qty	Unit Issue	Unit Price	Ln Total Or Contract Amount
1	Review - Mid-Atlantic Resiliency Link (MARL)				0.00

Comm Code	Manufacturer	Specification	Model #
81100000			

Commodity Line Comments:

Extended Description:

Please see attached documentation for further details.



Bates White Response to EOI for Mid-Atlantic Resiliency Link (MARL) Review

West Virginia Public Service Commission CEOI 0926
PSC2600000002

Submitted by:

Bates White Economic Consulting

May 06, 2026

BATES WHITE
ECONOMIC CONSULTING

Table of contents

Executive summary

Bates White is pleased to present our proposal to assist the Staff of the West Virginia Public Service Commission ("PSC" or "Commission") in evaluating the proposed Mid-Atlantic Resiliency Link ("MARL") transmission project. As stated in the Expression of Interest ("EOI"), this evaluation will encompass 1) the need for MARL to be installed across the lands of West Virginia, and 2) the economic impact to the State as a result of the MARL project ("Project").

The Bates White experts included in this proposal have performed validation studies of the asserted need for major transmission projects, and have conducted economic impact analyses for transmission projects, including for another of the PJM Window 3 reliability projects (the Maryland Piedmont Reliability Project), and for other large scale energy infrastructure projects. Our experts have evaluated transmission planning in jurisdictions across the country, and have assessed the challenges of long-horizon planning in the context of major changes over the past two decades – including the rapid expansion of intermittent renewable generation, the retirement of large volumes of legacy generation capacity, and most recently the unprecedented growth of very large data center loads and the attendant need for increased generation capacity.

The challenges of transmission planning in a rapidly changing environment are not trivial. There is substantial uncertainty regarding the location and magnitude of load growth, generation technology, public policy, and other factors relevant to the need for, and value of, transmission investment. There is also a dynamic question of how load and generation in the future will be influenced by near-term transmission development that complicates the basis on which the projected benefits of new transmission are evaluated.

Our evaluations of transmission planning and specific transmission projects – particularly in the context of large, multi-state RTOs, such as PJM, have highlighted concerns relevant to the evaluation of the MARL project. These include the reliability of load forecasting across many utilities and state jurisdictions, the appropriateness of future scenarios incorporated in the planning process for evaluating transmission need, and the range of solution alternatives considered.

With respect to evaluating the local economic impact of proposed transmission, we have experience in assessing true net effects based on clearly supported local spend estimates for both facility construction and operations over the asset life.

Our Team Lead will be Collin Cain, Partner at Bates White, and Chair of the Energy Practice. Mr. Cain will also lead the economic impact analysis component of the work as well as addressing PJM market related issues. Dr. Spencer Yang will lead the transmission need analysis, including performing required load flow analysis, and the identification and assessment of alternative solutions to the PJM-identified reliability need addressed by MARL. Mr. Nicolás Puga, former Partner with Bates White, currently affiliated with the firm as an independent contractor, will provide guidance and input to the required analyses.

The background and experience of the team experts are described below, and CVs are attached.

We appreciate the opportunity to respond to the EOI and look forward to assisting the Staff in this assignment.

Collin Cain

Partner

DESIGNATED CONTACT: Vendor appoints the individual identified in this Section as the Contract Administrator and the initial point of contact for matters relating to this Contract.

(Printed Name and Title) -- Christopher Gegenheimer – Practice Manager
(Address) 2001 K Street NW, North Building, Suite 500, Washington, DC 20006
(Phone Number) / (Fax Number) 202.215.2337 / 202.408.7838
(email address) chris.gegenheimer@bateswhite.com

CERTIFICATION AND SIGNATURE: By signing below, or submitting documentation through *wv*OASIS, I certify that: I have reviewed this Solicitation/Contract in its entirety; that I understand the requirements, terms and conditions, and other information contained herein; that this bid, offer or proposal constitutes an offer to the State that cannot be unilaterally withdrawn; that the product or service proposed meets the mandatory requirements contained in the Solicitation/Contract for that product or service, unless otherwise stated herein; that the Vendor accepts the terms and conditions contained in the Solicitation, unless otherwise stated herein; that I am submitting this bid, offer or proposal for review and consideration; that this bid or offer was made without prior understanding, agreement, or connection with any entity submitting a bid or offer for the same material, supplies, equipment or services; that this bid or offer is in all respects fair and without collusion or fraud; that this Contract is accepted or entered into without any prior understanding, agreement, or connection to any other entity that could be considered a violation of law; that I am authorized by the Vendor to execute and submit this bid, offer, or proposal, or any documents related thereto on Vendor's behalf; that I am authorized to bind the vendor in a contractual relationship; and that to the best of my knowledge, the vendor has properly registered with any State agency that may require registration.

By signing below, I further certify that I understand this Contract is subject to the provisions of West Virginia Code § 5A-3-62, which automatically voids certain contract clauses that violate State law; and that pursuant to W. Va. Code 5A-3-63, the entity entering into this contract is prohibited from engaging in a boycott against Israel.

(Company) Bates White

Collin Cain

(Signature of Authorized Representative)

(Printed Name and Title) -- Collin Cain - Partner
(Phone Number) / (Fax Number) 202.216.1156 / 202.408.7838
(email address) Collin.Cain@bateswhite.com

I. Mid-Atlantic Resiliency Link (MARL) Project Background and Context

I.A. PJM and transmission expansion

Through previous engagements on behalf of state regulators, public utilities, private sector entities, and multiple RTOs including PJM, Bates White has amassed a deep understanding of electric transmission and power systems across the United States. Below, we describe our understanding of the current sector landscape in the U.S., in the PJM region, and in West Virginia, specifically.

Because of accelerating power sector changes, and the associated identification of new transmission needs, questions pertaining to the determination of the most effective and equitable way to meet the needs have become more urgent. S&P Global Commodity Insights projects that the share of capital expenditures associated with transmission by North American electric utilities will increase from 18.4% in 2024 to 22% by 2030.[1] Similarly, Morningstar DBRS forecasts a national "super-cycle" of electricity infrastructure investment totaling $1.4 trillion in the remaining part of the decade.[2] These broad national trends heighten the importance of assessing the necessity and prudence of transmission expansion options.

In 2011, the Federal Energy Regulatory Commission (FERC) formalized the importance of cost-effective alternatives evaluation and benefit-cost allocation for transmission planning through FERC Order 1000, which mandated public utility transmission providers establish formal planning and cost allocation processes for new transmission facilities.[3] Reforms in FERC Order 1000 target two primary objectives:[4]

(1) Ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively.

(2) Ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them.

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[1] S&P Global Commodity Insights, "US data center load regulations emerge amid efforts to mitigate electricity rate concerns," December 2025, 5.

[2] Morningstar DBRS, "Power Hungry Data Centers Raise Capex Forecasts for North American Utilities," October 27, 2025, 1-2.

[3] Federal Energy Regulatory Commission, Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (2011), https://www.ferc.gov/sites/default/files/2020-04/orderno.1000.pdf (hereinafter "FERC Order 1000")

[4] FERC Order 1000 at 10.

With Allegheny Power Systems' (APS) 10-year zonal load projected to grow by approximately 3% annually[5] and PJM's net energy load forecasted to grow by an average of 5.3% per year[6], it is critical to evaluate both the necessity for the NextEra MidAtlantic Resiliency Link project ("MARL Project" or "Project") and its economic impact to the state and citizens of West Virginia.

I.B. PJM Regional Transmission Expansion Plan (RTEP)

PJM's Regional Expansion Plan (RTEP) identifies transmission system additions, upgrades, and improvements intended to enhance the electric grid to better accommodate load growth and generation interconnections.[7] PJM's RTEP process applies North American Energy Reliability Corporation's (NERC) Planning Standard TPL-001-5 through a range of analyses, including load and generation deliverability tests across a 15-year planning horizon.[8] As a part of this process, PJM conducts a competitive solicitation for new baseline and network transmission projects, based on an annual forward-looking load forecast report.[9] Eligible projects target specific needs, including delivering generation, improving market efficiency, replacing aging infrastructure, or enhancing operational performance. Following identification of projects through the solicitation process, the PJM Board of Managers approves system recommended system enhancements, new facilities, and upgrades to existing facilities.[10]

Across all solicitation windows, in 2025 PJM approved 122 new baseline projects and 445 new network transmission projects, totaling an estimated approximately $13 billion.[11] The MARL Project was selected as a part of the 2022 RTEP Window 3 solicitation.[12]

I.C. MARL Project

As a part of PJM's RTEP process, and in response to accelerated load growth in the region and new generation additions in western PJM, the MARL Project was selected in 2023 through a competitive solicitation process and aimed to reinforce the reliability of the electric grid.[13] The Project includes a new 107.5-mile, 500 kV transmission line traversing portions of Pennsylvania, West Virginia, Maryland, and

[5] PJM, 2026 Load Forecast Report, January 14, 2026, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf at 27 ("PJM 2026 Load Forecast Report")
[6] Allegheny Power Systems operates the utility company Monongahela Power in West Virginia and is a part of PJM. PJM 2026 Load Forecast Report at 6.
[7] https://www.pjm.com/library/reports-notices/rtep-documents.aspx
[8] PJM, RTEP 2025 Regional transmission Expansion Plan, April 17, 2026, https://www.pjm.com/-/media/DotCom/library/reports-notices/2025-rtep/2025-rtep-report.pdf at 13 ("2025 RTEP Report").
[9] 2025 RTEP Report at 6.
[10] 2025 RTEP Report at 3.
[11] 2025 RTEP Report at 61.
[12] "NextEra Energy Transmission MidAtlantic transmission proposal selected by PJM," NextEra Energy, December 11, 2023, https://www.investor.nexteraenergy.com/news-and-events/news-releases/2023/12-11-2023-000207841.
[13] https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/

Virginia.[14] Approximately 58.9 miles of the 500 kV transmission line will be located in Monongalia, Preston, Mineral, and Hampshire Counties in West Virginia. The Project also includes a new 500/138kV Woodside Substation to be located in Virginia.

The MARL Project was originally proposed and awarded in PJM's 2022 RTEP Window 3 to address system overload issues in the Maryland and Virginia regions. PJM's reliability analysis identified thermal overload and voltage collapse reliability violations that could occur in the region as early as 2027.[15] PJM concluded the MARL Project was a more cost-effective solution to address the reliability issues in West to East transfers and would offer a 500 kV supply line into the Dominion zone.[16]

The MARL Project is estimated to cost approximately $959 million (expressed in 2023 dollars) and is expected to be escalated to approximately $1.2 billion by its 2031 target in-service date.[17] Notably, when initially proposed in 2023, the total cost for the project was $441 million.[18] According to NextEra and PJM, these cost increases reflect "30% design and engineering," "higher than budgetary quotes" for equipment, and "refinements to project route alternatives and engineering assessments of substation site conditions."[19] Further, the updated cost estimate reflects "an additional $115.4 million of contingency to cover risk-based costs, including potential route changes and market uncertainty."[20] The MARL Project proposal also includes binding cost containment measures that reduce the return on equity on capital expenditures in excess of the original cost estimate.[21]

I.D. West Virginia economic development

West Virginia, given its proximity to the nation's capital, Washington D.C. and the high density of data centers in the Northern Virginia region (also known as "Data Center Alley"), is well positioned to facilitate data center and related infrastructure investment in the state. PJM has noted that data center load growth is causing unanticipated changes to load forecasts in the West Virginia region, with annual load

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[14] NextEra Energy Transmission MidAtlantic, Inc., *Application for Certificate of Public Convenience and Necessity and Related Relief*, Public Service Commission of West Virginia, January 30, 2026, 3 (hereinafter "Application")
[15] Application at 15.
[16] Application at 17.
[17] Application at 20.
[18] https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-item-09---reliability-analysis-update.pdf at 66.
[19] https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-item-09---reliability-analysis-update.pdf at 68.
[20] https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-item-09---reliability-analysis-update.pdf at 68.
[21] Application at 22.

growth projected at approximately 3%.[22] In addition, on April 30, 2025, West Virginia Governor Patrick Morrisey signed House Bill 2014 into law which incentivizes data center development in the state by creating a specialized tax structure, curtailing local regulatory processes and zoning ordinances, and allowing data centers to produce and bring their own power.[23] This legislation also establishes microgrid districts, or zones where electricity generated within specified area will "be used only within the microgrid district or delivered to the wholesale market."[24] This structure allows entities to provide electric service through generation or distribution of electricity without being subject to traditional commission jurisdiction and enables up to 10% of electricity generated sold in wholesale markets as an "exempt wholesale generator."[25]

Lastly, the Public Service Commission of West Virginia recently approved Appalachian Power Company's and Wheeling Power Company's request to establish a Large Capacity Power Service Schedule ("Schedule L.C.P."), standardizing the terms and conditions for large load customers with 150 MW or greater of aggregate load within their service areas.[26] It is clear at the regional, state, and utility levels that the benefits of specific transmission investment, such as MARL, must be evaluated in the context of West Virginia's economic development and the costs borne by its ratepayers.

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22 APS load forecast has changed in due to growth in data center load. APS operates Monongahela Power in West Virginia. See https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-item-09---reliability-analysis-update.pdf at 5.

23 "Morrisey signs priority bill meant to incentivize data centers, microgrids locating in WV," West Virginia Watch, April 30, 2025, https://westvirginiawatch.com/2025/04/30/morrisey-signs-priority-bill-meant-to-incentivize-data-centers-micro-grids-locating-in-wv/.

24 Chapter 5B. Economic Development Act of 1985, §5B-2-21 ("HB 2014").

25 HB 2014 §(c)(3)

26 Schedule L.C.P. (Large Capacity Power Service), August 28, 2025, https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/2025_Base_Case_Tariff_11-17-2025.pdf at 70.

II. Approach to Achieving Project Goals

II.A. Approach to Analysis of the Need for the MARL Project

II.A.1. Review analysis performed by PJM

The Bates White team will review the analysis performed by PJM and/or the Applicant relating to the MARL Project and will assess the reasonableness of the data inputs and modeling assumptions used in the analysis to support the need for the proposed line. As stated in the EOI, the work will include assessment of the following inputs, assumptions, and methodological approaches:

- Load forecasting;
- New generator assumptions and support for including or excluding specific generators;
- Use of out-of-merit-order generator dispatch to solve overloads;
- Manual adjustments made in N-1-1 contingencies;
- Studies of reconductoring and re-tensioning or uprating of existing transmission lines;
- Impacts from other factors affecting need, such as projected results of Reliability Pricing Model auctions, and potential Green House Gas impacts; and
- Evaluation of alternative generation, transmission and demand response/energy efficiency options, including upgrades to existing infrastructure.

We will investigate the effects and sensitivities on the reliability need for the proposed MARL with respect to changes in load, generation, and transmission assumptions associated with PJM's ongoing RTEP updates. In particular, we will verify whether all generation and transmission interconnection projects that have executed ISAs were fully recognized in the PJM RTEP power flow cases and model updates that we understand are currently in progress. Prior to filing written testimony, we will update analyses, conclusions, and recommendations based on the most up-to-date information and data of the PJM RTEP.

II.A.2. Review of Application

We will review the Application to determine whether it satisfies the requirements of the Commission's Rules and Regulations for the Government of Electric Utilities, Rule 9, concerning the required information in an application for certificate of public convenience and necessity.[27] Specifically, we will evaluate and assess the Applicant's required statements concerning the type of line to be constructed, description of the line and its attributes, consideration for alternate routes for said right-of-way, among

[27] Rules for the Government of Electric Utilities, Public Service Company of West Virginia, §150-3-9 ("Rule 9")

other technical required elements. With respect to the Rule 9 provisions regarding potential impacts on wildlife habitat, animal and human health, and the environment, we will assess whether the Applicant's submission complies with the requirements. We will not perform an independent validation of the information provided by the Applicant.

In addition, we will also evaluate the substance of the Application as it relates to the need for and economics of the proposed MARL line.

The independent needs assessment will consist of the following steps:

1. Prepare contingency analyses – e.g., acquire, validate, and integrate necessary data inputs, modeling assumptions, and power flow cases to conduct contingency analyses.
2. Conduct contingency analyses – e.g., to determine reliability needs based on NERC, PJM and the Applicant's planning criteria.
3. Classify and summarize results – e.g., relevant limiting facilities and contingency elements obtained from contingency analyses for both West Virginia reliability as well as PJM regional reliability as a whole.

Specifically, we will prepare and carry out contingency analyses using PowerWorld Simulator, an interactive power systems simulation software package, in order to evaluate transmission system responses under single, sequential, and multiple contingency conditions. First, we will validate and integrate all necessary data inputs, make and document all necessary modeling assumptions and prepare the necessary power flow cases to be used in the contingency analysis. Then, we will conduct contingency analyses to determine the reliability need for the line based on NERC, PJM, and the Applicant's planning criteria. Finally, we will classify relevant limiting facilities and contingency elements obtained from contingency analyses and summarize material impacts on both West Virginia reliability as well as PJM regional reliability as a whole.

II.A.3. Review of Transmission vs. Non-Transmission methods

If a reliability need is substantiated, we will evaluate proposed alternatives to the MARL Project.   We will determine whether that need can be met with non-transmission alternatives such as new generation or expanded demand response; we will assess whether transmission expansion is the most cost-effective alternative; and we will address whether MARL is the best transmission alternative to meet the need while balancing all of the competing interests of the State and its citizens. We will assess the Applicant's detailed investigation of all alternatives studied and related supporting files, as required by Rule 9. Such alternatives will include any alternatives considered explicitly by the Applicant or by PJM in modeling for RTEP. We will also consider any other proposed transmission or non-transmission alternatives identified in consultation with Commission Staff.

In addition, we will also address whether the proposed MARL Project provides the best course of action regarding construction options, such as line sizing and selected materials to meet the need, while balancing all of the competing interests of the State and its citizens.

Lastly, we will also assess the potential effects of the proposed MARL transmission line on meeting the State's economic development priorities, including those outlined in House Bill 2014, such as the promotion of data center development and microgrid district development.[28] Beyond evaluation of potential effects on data center development, we will assess whether the proposed line has the potential to increase the availability of in-state generation for delivery outside the State and whether the line could have beneficial effects on the Governor's strategic plan to increase West Virginia's energy capacity from 15 gigawatts today to 50 gigawatts by 2050.[29]

II.B. Approach to Analyzing Economic Impacts of the MARL Project

II.B.1. Economic Impact Analysis

We will assess the potential direct economic impacts resulting from the development and operation of the MARL project to West Virginia and its citizens. We plan on utilizing the Jobs and Economic Development Impacts (JEDI) Transmission Line Model, developed by the U.S. National Research Energy Laboratory, which allows for estimation of the flow of economic effects throughout the economy, including impacts on jobs, earnings, economic value added, and tax revenue.

We believe the JEDI Transmission Line Model is an appropriate tool to assess the economic impacts from construction and operation of the MARL project. Members of the proposed Bates White team have also performed economic impact analyses using IMPLAN's data and analysis tools. An advantage of IMPLAN is that it could allow for county-level impact assessment, subject to the availability of relevant spend data with corresponding granularity. That added capability also comes with increased cost, as the use of IMPLAN would require a license fee, while the JEDI model is provided free of charge. In consultation with Staff, we will determine whether IMPLAN would provide additional value in this assignment relative to JEDI.

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28 See description of West Virginia economic development objectives in Section I.D.

29 "Governor Patrick Morrisey Announces Comprehensive Energy Policy Framework to Make West Virginia Energy Dominant," West Virginia Office of the Governor, September 10, 2025, https://governor.wv.gov/article/governor-patrick-morrisey-announces-comprehensive-energy-policy-framework-make-west.

II.B.2. Evaluation of information provided by applicant

We will evaluate the Applicant's claims regarding the economic impacts of the MARL Project on West Virginia and its residents to determine whether those claims are supported. This review will include an assessment of the Applicant's filings, testimony, and supporting workpapers. Specifically, we will evaluate the Applicant's analysis of the projected impact on West Virginia retail rates and the direct, indirect, and induced economic effects attributed to the project, as well as any other economic impact analyses presented by the Applicant. Where necessary supporting information is not available in the filed materials, we will prepare data requests and interrogatories to obtain the information needed to thoroughly assess the Applicant's assertions concerning economic impacts to West Virginia and its citizens.

III. Qualifications, Experience, and Past Performance

III.A. Capacity of Bates White to Complete Work Within Specified Time Frame

Bates White is a leading consulting firm providing economic, engineering and technical analysis. Bates White's energy experts have extensive experience in power system analysis, transmission planning, project development, electricity market design, forecasting and forensic analysis, and have testified and advised on a range of issues including transmission need assessment, cost allocation and economic impact analysis.

Bates White transmission and regulatory experts have worked across all major U.S. transmission markets including CAISO, ERCOT, MISO, NYISO, SPP and PJM. For example, we assisted the Staff of the Virginia Corporation Commission in carrying out an independent assessment of need for the 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500 kV Transmission Line (TRAIL Line). The work involved contingency analysis of multiple transmission, generation and demand response alternatives meant to substitute for the proposed transmission line. The contingency analysis performed required replication of the power flows used by the proponents to support their application. To that end, our transmission experts interacted extensively with transmission engineers at Dominion Virginia Power, TrailCo and PJM to obtain and run the correct power flow cases. Our experts documented the results of the contingency analyses carried out in a report, and testified as to the ability of these alternatives, including PJM's RPM demand response programs, to provide the same level of long-term reliability as that of the proposed line.

The key participants in the analysis will be Spencer Yang, Collin Cain and Nick Puga. Dr. Yang has extensive experience in reliability and power flow studies in various U.S. transmission regions, including PJM. Mr. Cain has extensive experience in addressing critical economic and regulatory issues that affect electric and gas utility markets and infrastructure, including PJM, and has conducted economic impact analyses for large scale energy infrastructure projects, including the Maryland Piedmont Reliability Project, which, like MARL, is a PJM Window 3 reliability transmission project. Mr. Puga has more than 25 years of experience as senior energy advisor to regulators, electric utilities and generation and transmission developers. He has testified as an expert in several state transmission line and power plant certification and abandonment proceedings in California, Kansas, New York, Texas, Virginia, and at the Federal Energy Regulatory Commission.

Other Bates White consultants will be called upon as needed to properly match experience and training with the project's requirements and to keep costs down. Brief biographies of the key Bates White experts who will participate in this engagement are presented in Section III.B below; their full CVs are presented as attachments to this proposal.

III.A.1. Experience in Transmission Analysis

Transmission needs assessment for TRAIL project, VASCC.

Bates White experts assisted the Staff of the Virginia Corporation Commission in carrying out an independent assessment of need for the 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500 kV Transmission Line for the Virginia. The work involved contingency analyses and multiple transmission, generation and demand response alternatives to potentially obviate the need for the proposed transmission line. The contingency analyses performed required replication of the power flows used by the proponents to support their application. To that end, our transmission experts interacted extensively with transmission engineers at Dominion Virginia Power, TrailCo and PJM to obtain and run the correct power flow cases. Our experts documented the results of the contingency analyses carried out in a report, and testified as to the ability of these alternatives, including PJM's RPM demand response programs, to provide the same level of long-term reliability as that of the proposed line.

Transmission needs assessment and economic impact analysis for PATH project, WVPSC.

On behalf of the Public Service Commission of West Virginia, Bates White experts evaluated the application for a certificate of public convenience and necessity for the Potomac-Appalachian Transmission Highline (PATH) with the West Virginia Public Service Commission. The proposed transmission line was planned to extend 275 miles, from Putnam County WV to New Market MD, at an estimated cost of $1.8 billion to construct. Bates White experts performed a reliability needs assessment and economic impact analysis to determine whether the need for the project, and its impact on West Virginia, were properly supported in the application. The reliability need was evaluated using power flow analysis of the PJM system. Bates White experts evaluated whether the reliability need was met cost-effectively by the PATH proposals and whether alternatives provided superior and/or lower cost solutions. Bates White experts also performed an economic impact analysis of the project's impacts on the West Virginia economy through construction and operation of the in-state facilities. The PATH application was withdrawn prior to submission of Bates White testimony.

FERC seven-factor analysis for certain SPP assets, FERC

On behalf of OG&E and Western Farmers, Bates White performed FERC's seven-factor analysis to determine whether the Applicant's facilities are transmission facilities. To carry out the task, Bates White performed detailed SPP zonal-level power flow analysis to assess, among other things: whether the facilities are normally in close proximity to retail customers; whether the facilities are primarily radial in character; whether power flows rarely, if ever flows out; when power enters a local distribution system, it is not reconsigned or transported on to some other market; whether power is consumed in a comparatively restricted geographic area; whether meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and whether facilities are of reduced voltage.

Transmission needs assessment for Houston Import Project (HIP), PUCT.

On behalf of Calpine and NRG, Bates White performed an independent assessment for Houston Import Project (HIP). The work involved contingency analyses and multiple transmission, generation and demand response alternatives that might obviate the proposed transmission line. The contingency analyses performed required accurate modeling of the ERCOT system with and without the HIP Project. Our experts documented the results of the contingency analyses carried out in a report, and testified as to the ability of these alternatives, including ERCOT's other generation, transmission and demand response programs, to provide the same level of long-term reliability as that of the proposed line.

NYRI Proceeding before the New York Public Service Commission. Case No. 06-T-0650.

Bates White performed the analysis of costs and benefits of proposed HVDC line in NYISO. Analysis included production cost modeling study on behalf of New York Regional Interconnect, Inc. (NYRI), and qualitative analysis of costs and benefits of the line to meet state renewable portfolio standard mandates. Implementation of both zonal and nodal production cost simulation modeling studies

Simultaneous Import Capability study for Entergy Control Area, FERC.

Bates White expert performed Simultaneous Import Capability (SIC) study for Entergy control area on behalf of Calpine Corporation and Occidental Chemical Corporation in FERC market based rate (MBR) proceeding (Docket No. ER91-569-023).

III.A.2. Experience in Economic Impact Analysis

Economic Impact Analysis of the Maryland Piedmont Reliability Project

On behalf of the project developer, PSEG Renewable Transmission LLC, Bates White conducted an economic impact analysis of the Maryland Piedmont Reliability Project ("MPRP"). MPRP is a greenfield 500kV AC overhead transmission line proposed to PJM as a solution to forecasted system reliability violations identified in PJM's 2022 RTEP Window 3 solicitation. Bates White quantified the economic impacts to Maryland from development, construction and operation of the MPRP by applying the JEDI Transmission Line model, developed by the U.S. National Research Energy Laboratory. The analysis estimated direct, indirect and induced impacts on jobs, earnings, economic value added, economic output, and tax revenue.

The report and associated testimony filed with the Maryland Public Service Commission are provided as an attachment to this proposal.

Comprehensive economic impact analysis for Skipjack Offshore Energy, LLC (Ørsted), Maryland Public Service Commission

On behalf Skipjack Offshore Energy, LLC (Ørsted) before the Maryland Public Service Commission, Bates White conducted a comprehensive economic impact analysis of the proposed Skipjack Offshore Wind Project, offered into Maryland's Round 2 Offshore Wind procurement process. Consistent with Maryland's regulatory requirements for the process, Bates White's estimation of costs and benefits to the state included: (1) Economic input-output analysis of in-state impact on income, employment, wages, and state and local taxes, performed using the National Research Energy Laboratory (NREL) Joint Economic Development Impact (JEDI) model; (2) Analysis of anticipated environmental and health impacts including direct emissions impacts related to carbon dioxide, oxides of nitrogen, sulfur dioxide, particulates and mercury emissions; (3) Analysis of the effects on wholesale energy, capacity, and ancillary services markets administered by PJM; (4) Analysis of any other benefits to the State such as in-state construction, operations, maintenance, and equipment purchases; and (5) Analysis of impacts to retail electricity rates for residential and non-residential customers over a 30 year time horizon.

Long range transmission planning, futures modeling, cost allocation – Mississippi

Bates White has provided technical and advisory services to staff of the Mississippi Public Service Commission for more than a decade. Bates White has advised the MPSC on a variety of matters related to participation in MISO, including long range transmission planning, modeling of future economic and market conditions in the evaluation of transmission expansion alternatives, and transmission categorization and cost allocation.

On behalf of the Mississippi Public Utilities Staff, the regulatory entity external to the MPSC, Bates White has assessed the annual Transmission and Distribution Plans of the jurisdictional utilities Entergy Mississippi, LLC, and Mississippi Power Company, from 2016 to the present.

III.B. Relevant Experience – Consultant Staff

III.B.1. Collin Cain

Mr. Cain is a Partner with Bates White and Chair of the firm's Energy Practice. He specializes in power sector economic analysis, including economic impact analysis, market design, cost allocation, cost benefit analysis, and contract damages. He has provided testimony and advised clients on a wide range of power sector issues in PJM, MISO, ISO New England, NYISO, ERCOT, Ontario, Alberta, and Mexico. Mr. Cain has testified at FERC and before state regulatory commissions on cost benefit analysis, cost allocation, the conduct and application of forecasts, market behavior, market power, risk assessment by contract counterparties, and contract damages.

- Mr. Cain has been co-lead on all work Bates White has performed on behalf of the Mississippi Public Service Commission over the past decade. This work has included evaluation of long range transmission planning, transmission categorization and cost allocation; modeling of future economic and market conditions in the evaluation of transmission expansion alternatives; assessment of capacity zone definitions and determination of transfer limits; analysis of capacity market design, scarcity pricing initiatives, capacity accreditation, interconnection queue reform; and evaluation of the Joint Targeted Interconnection Queue (JTIQ), a collaboration between MISO and SPP to identify cross-seam transmission projects to improve reliability and expand renewables.
- Mr. Cain has led or co-led all work by Bates White on behalf of the Mississippi Public Utilities Staff (MPUS), including the assessments of the Transmission/Distribution (T&D) and Energy Delivery Plans of Entergy Mississippi, LLC (EML) each year since 2016; and assessments of the annual Capital Plans and Energy Delivery Plans of Mississippi Power Company (MPC).
- Mr. Cain performed an economic impact analysis of the MPRP transmission project on the state of Maryland, described in Section III.A.2, above, and sponsored associated testimony filed with the Maryland Public Service Commission.
- Mr. Cain conducted the comprehensive cost benefit analysis of the Skipjack Offshore Wind Project described in Section III.A.2, above, and sponsored associated testimony filed with the Maryland Public Service Commission.
- FERC Docket EL07-57-000. Mr. Cain evaluated PJM proposals to modify the Open Access Transmission Tariff (OATT) allocation of cost responsibility for transmission upgrades under the Regional Transmission Expansion Plan (RTEP) and supported related testimony.

III.B.2. Spencer Yang

Spencer Yang, Ph.D., is a Principal in the Bates White Energy Practice. Dr. Yang provides expert testimony and consulting services for transmission modeling, interconnection analysis, estimation of available transfer capability and simultaneous import capability, contingency analysis, reliability need assessment, electricity market analysis, litigation, and energy-related regulatory proceedings. He has extensive experience applying quantitative analysis to a broad range of transmission issues and challenges. Dr. Yang has performed detailed power flow modeling and simulation analysis in most U.S. electricity markets. Among other models, he has used PowerWorld Simulator, an interactive power system simulation package designed to simulate high voltage power system. The software contains a highly effective power flow analysis package capable of efficiently solving systems of up to 250,000 buses. The program is widely used by utilities and regulatory agencies, including FERC. Dr. Yang has served as both a testifying and consulting expert in a wide array of transmission-related cases, including the Exelon–Constellation merger, FERC PURPA section 210(m) proceeding, QF interconnection analysis, reliability need assessment of transmission lines, contingency analysis, potential reliability impact of the retirement of nuclear generation facilities, and various federal, state and civil cases that require detailed transmission system modeling. Specifically:

- Dr. Yang testified on behalf of Oklahoma Gas & Electric Company (OG&E) and Western Farmers in the FERC proceeding related to the determination of whether the PEC Facilities qualify as transmission for rate recovery under the SPP Tariff (FERC Docket No. ER22-1525).
- Dr. Yang testified on behalf of Calpine and NRG regarding certificates of public convenience and necessity to construct the Houston Import Project (SOAH Docket No. 473-15-3595).
- Dr. Yang testified on behalf of Virginia State Corporation Commission Staff regarding certificates of public convenience and necessity to construct a 500-kV TrAIL transmission line (Case Nos. PUE-2007-00031 and PUE-2007-00033).
- Dr. Yang conducted PROMOD benchmarking analysis on behalf of MISO to improve the transmission planning and transmission congestion modelling process.
- Dr. Yang conducted a full production cost modeling study on behalf of the New York Regional Interconnect, Inc. (NYRI) related to NYRI's application to the New York PSC to construct a 1200-MW HVDC transmission line.

III.B.3. Nick Puga

Nicolás Puga, M.Sc., is a Bates White affiliate and former Partner and Energy Practice Chair. Mr. Puga has more than 25 years of experience as senior energy advisor to electric utilities and generation and transmission companies in the analysis of electric power and natural gas markets, generation and transmission project development, utility resource supply planning, and renewable energy resource development. He has testified as an expert in several state transmission line and power plant certification and abandonment proceedings in California, Kansas, New York, Texas, Virginia, West Virginia and at the Federal Energy Regulatory Commission. Mr. Puga has been an advisor to the Mississippi Public Service Commission and the MS Public Utility Staff since 2012, including in the evaluation of Entergy's proposal to join MISO; the evaluation of Entergy's proposal to spin off its transmission assets to ITC; and on issues related to regional and interregional long-term transmission planning and cost allocation in MISO and neighboring transmission systems. In Southwest Power Pool, Inc. GridLiance High Plains

LLC, Dockets No ER18-2358-001 and No. ER19-1357-000 (consolidated) Mr. Puga was retained by the Southwestern Public Service Company to show that the analyses introduced by Gridliance High Plains witnesses relied on inappropriate methods to answer the questions raised in that proceeding, and that those methods are not capable of producing the information that GHP's witnesses claimed to rely on to arrive at their conclusions.

In Southwest Power Pool, Inc., PERC Docket No. ER18-99-005 Mr. Puga was retained to testify on behalf of a group of transmission owners and transmission dependent cities in SPP to contest the appropriateness and accuracy of applying the analytical methods used by a transmission asset owner to quantify and allocate power flow based benefits and costs of those assets to load.

Table 1 below provides an estimate for the anticipated number of hours for the experts assigned to this project. Additional time Bates White consulting staff needed to support the analyses are not included and thus Table 1 is not an estimation of the total level of effort required to complete the scope.

Staff Member Name	**Role**	**Estimated Hours**
Spencer Yang	Reliability needs analysis	340
Collin Cain	Economic impact analysis	220
Nick Puga	Non-transmission alternatives analysis	130

Table 1 – Estimated Level of Effort for Expert Consultant Staff

III.C. Conflicts of Interest

Bates White, LLC is not aware of anything that would impair our ability to provide independent and objective services in this matter. To the best of our knowledge, Bates White is not currently engaged by NextEra Energy, Inc. or any of its subsidiaries. In the past 5 years, Bates White has worked adverse to or where NextEra Energy, Inc. and some of its subsidiaries were interested parties in unrelated matters. In our energy practice, we are currently serving or have previously provided services to public utility commissions in the District of Columbia Public Service Commission, Washington State, Hawaii, Illinois, Kansas, Maryland, Massachusetts, Mississippi, Nebraska, New Jersey, Ohio, Oklahoma, Oregon, and Nova Scotia and that work may have directly or indirectly concerned NextEra Energy, Inc. or its subordinates or affiliates.

Bates White has over 200 degreed professionals and is engaged by many different clients, ranging from corporations to other business entities, law firms, and government entities, including those with adverse, competitive or opposing interests. Bates White reserves the right to work for these or any other entities in matters other than the present one. Bates White is committed to protecting the confidential information of clients, and Bates White may establish internal walls if deemed necessary in Bates White's discretion and at such time as Bates White deems necessary and appropriate.

III.D. Professional Resumes

Professional Resumes for Collin Cain, Spencer Yang, and Nick Puga are provided in Annex A.

III.E. Previous Work Product

Three examples of previous and similar work performed by staff who will be assigned to this project are included in Annex B.

III.F. Client References

Three client references are provided below

Reference 1

Client:	Western Farmers Electric Cooperative
Contact:	Mr. Matthew A. Caves V.P., Legal & Regulatory Compliance Tel: (405) 759-2784
Case	FERC Docket No. ER22-1525
Case Description	This case concerns whether the Applicant's facilities qualify as transmission
Service Type	Expert testimony
Service Description	Bates White performed detailed bus-level power flow analysis using PowerWorld Simulator transmission modeling software and opined that the Applicant's facilities do not qualify as transmission. FERC's Initial Decision issued in April 2025 determined that most of the Applicant's facilities do not qualify as transmission.
Duration:	2022-2025

Reference 2

Client:	Virginia State Corporation Commission
Contact:	Mr. Tom Lamm[30] Assistant Director, Division of Energy Regulation Tel: (804) 371-9392 (General Counsel's Office: 804-371-9671)
Case	PUE-2007-00031 and PUE-2007-00033
Case Description	This case concerns whether the proposed TRAIL line was needed for reliability purposes
Service Type	Expert testimony
Service Description	Bates White experts performed contingency analyses and multiple transmission, generation and demand response alternatives to potentially obviate the need for the proposed transmission line. The contingency analyses performed required replication of the power flows used by the Applicants to support their application. To that end, our transmission experts interacted extensively with transmission engineers at Dominion Virginia Power, TrailCo and PJM to obtain and run the correct power flow cases. Our experts documented the results of the contingency analyses carried out in a report, and testified as to the ability of these alternatives, including PJM's RPM demand response programs, to provide the same level of long-term reliability as that of the proposed line.
Duration:	2007-2008

[30] Note: contact information at the time of the service provision in 2007. We have not been able to confirm current personnel at the VA SCC familiar with this assignment. We have provided contact information for the General Counsel's Office as an alternative.

Reference 3

Client:	Skipjack Offshore Energy, LLC (Orsted)
Contact:	Mr. . Joseph (Max) Curran, III Partner, Venable LLP (outside counsel) Tel: (410) 244-5466
Case	Maryland PSC Docket No. 9666
Case Description	Offshore wind facility application under Maryland OWEA
Service Type	Analysis and expert testimony
Service Description	Bates White was retained to perform a cost benefit analysis for the Skipjack 2.1 Offshore Wind Project, to evaluate three regulatory tests established under the Maryland Offshore Wind Energy Act of 2013 (OWEA), the Clean Energy Jobs Act of 2019 (CEJA), and COMAR 20.61.06.02L, and to conduct an economic impact analysis using an input-output model for the state of Maryland.
Duration:	2021-2024

III.G. Proposed Project Schedule

Bates White anticipates that the MARL proceeding and the Consultant work will continue through the year 2026. Bates White also anticipates that the MARL proceeding is expected to involve extensive and complex discovery process from multiple parties. In addition, in the course of performing an independent needs assessment, if Bates White finds certain activities and changes that may significantly impact the conclusions and recommendations related to the need for the proposed line, we will promptly inform Staff of the impacts of these changes, and we will update our analyses and conclusions accordingly prior to filing and presenting written and oral testimony.

Consistent with the ambitious timeline described in the EOI, Bates White commits to providing regular updates on task progress and challenges to Staff to ensure efficient and effective completion of the tasks described in Section II. This will include periodic status updates scheduled at agreeable intervals to inform Staff of progress, our preliminary findings, and conclusions. We anticipate an accelerated project inception phase which will include finalizing the scope of several interim deadlines for draft work products necessary for Staff review and comment.

In addition, Bates White will provide the following deliverables according to the following timetable (based upon Commission's EOI):

Milestone	**Date**
Draft of Final Report / Testimony	August 28th, 2026
Final Report / Direct Testimony	September 8th, 2026
Rebuttal Testimony (if required)	October 7th, 2026
Present Testimony at Hearing	October 26th, 2026

Table 2 – Planned timeline

Annex A: Professional Resumes

BATES WHITE
ECONOMIC CONSULTING

2001 K Street NW North Building, Suite 500
Washington, DC 20006
Main 202. 408. 6110

COLLIN CAIN, MSC

Partner

AREAS OF EXPERTISE

- Economic, regulatory and market analysis
- Market design
- Asset valuation
- Damages estimation
- Forensic analysis

Summary of experience

Mr. Cain chairs the Energy Practice at Bates White. He specializes in economic evaluation of wholesale energy markets, spanning electricity, fuels and environmental attributes. He has provided testimony and advised clients on market design in PJM, MISO, ISO New England, NYISO, ERCOT, Ontario, and Alberta. He has developed energy and capacity market pricing and risk analysis models, and has applied these models in a variety of consulting assignments to forecast energy prices, evaluate market design, value generation assets and power supply contracts and to develop supply hedging strategies. Mr. Cain has provided expert testimony in regulatory, court and arbitration proceedings. He has provided strategic advisory work on issues such as asset divestment, stranded cost recovery, and rate unbundling. Mr. Cain also applies his expertise in forensic analysis of the conduct and application of forecasts, market evaluation, and risk assessment by contract counterparties.

Mr. Cain has provided expert testimony on forecasting, contract damages, market design, supply procurement, power market modeling, cost/benefit analysis, market power, cost allocation, and energy market bidding behavior.

Education

- MSc, Economics, London School of Economics
- BA, Economics and Political Science Specialist, University of Toronto

Selected experience

- On behalf of Mississippi Public Utility Staff, evaluated the proposed acquisition by Entergy Mississippi of a 100 MW solar project located in Sunflower County, MS. Assessed the rationale, evidentiary support, costs, benefits and risks associated with the proposed transaction. Submitted testimony before the Mississippi Public Service Commission.
- Evaluation of solar PPA transactions totaling 420 MW of installed capacity proposed by Entergy Mississippi as part of its “EDGE” resource strategy. Assessed the costs, benefits and risks of the proposed PPAs on behalf of Mississippi Public Utility Staff.

- On behalf of ALLETE Clean Energy, Inc., prepared fuel and electric energy price forecasts and estimated damages in an arbitration dispute regarding a virtual PPA contract.
- Conducted due diligence assessment of the financial modeling of off-taker PPA revenues for the 396MW Mareña wind power project in southern Mexico, including the representation of off-taker priority list weighting and energy banking under CRE renewable interconnection rules.
- On behalf of Mississippi Public Utility Staff, evaluation of the proposed acquisition by Entergy Mississippi of an additional, approximately 209 MW, share of the Grand Gulf Nuclear Station.
- Expert testimony on behalf of the Data Center Coalition, before the Public Utility Commission of Oregon, regarding novel rate design proposals by PacifiCorp applicable to very large loads. The testimony addressed economic and regulatory issues related to the development of electric utility rates, and the incentive impacts of the proposed capacity reservation charge mechanism relative to a minimum demand charge.
- For the owner of an IPP combined cycle power plant in Mexico, performed an analysis of plant residual value after the expiration of a 25 year PPA with CFE. The valuation applied two distinct methodologies: an “equivalent plant” approach, and a “cost-of-new-entry” approach, with multiple scenarios for capital costs and natural gas prices.
- As an advisor to a major capital finance entity, evaluated the project financial model for a proposed hydroelectric generation project in western Mexico. The model review considered representation of the renewable energy banking mechanism under Mexican energy regulation, representation of seasonal production and demand patterns, and the associated projection of profit and loss and debt service coverage of the life of the project.
- In support of a major wind farm development in Mexico conducted a due diligence review of the project PPA, price model and its application in projecting project revenues. The evaluation addressed the representation of the renewable energy banking mechanism and the priority lists for allocating project energy and capacity to load centers, and consistency with the CFE interconnection agreement.
- Multiple assignments for renewable fuels clients, analyzing impacts on end-use fuel pricing of state and federal renewable fuel support programs. Analyses addressed how costs are distributed among refiners, distributors, and retail customers, and also assessed the relative impact of volume mandates and tax credits.
- Study identifying and quantifying the primary drivers of transportation fuel prices in California. The study quantified California-specific effects from state fuel taxes, the Cap-and-Trade program, the Low Carbon Fuel Standard program (LCFS), and transient factors such as refinery outages and the COVID pandemic.
- Directed a multi-disciplinary team in the development of a new pricing mechanism for liquid fuels in South Africa. The work, performed for the South African Department of Minerals and Energy, examined cost components of retail fuel prices, including commodity, refining, distribution and retailing, and established pricing methods and regulatory accounts to ensure that wholesale and retail fuel prices appropriately reflect costs, and enhance industry investment incentives.
- Submitted expert declaration regarding exemptions to small refineries obligated under the Renewable Fuel Standard (RFS) program, supporting a Motion for Stay of Agency Action filed against the EPA by Producers of Renewables United for Integrity Truth and Transparency in the U.S. Court of Appeals for the D.C. Circuit.
- Evaluation of supply, demand and economics of renewable natural gas industry in the U.S., including production pathways and technologies, demand drivers, and support from state and federal programs, particularly EPA’s RFS and California’s LCFS programs.

- Evaluations of the 2024 integrated resource plans of Evergy (Kansas), Entergy Mississippi, and Mississippi Power.
- Expert testimony on behalf of the Kansas Corporation Commission Staff regarding the proposed acquisition of 800 MW of wind generation by Empire District Electric Company. Analysis included an assessment of energy and capacity needs, projected wind energy production, curtailment risk, projected value from proposed tax equity partnership, and risk allocation between investors and ratepayers.
- Affidavit in FERC proceeding (FERC Docket No. ER16-49-000, *et al.*) on behalf of the Electric Power Supply Association (EPSA) evaluating multiple proposals by PJM and other market participants to modify the PJM capacity market.
- In separate fuel audits of Nova Scotia Power for 2016-2017 and 2018-2019, on behalf of the Nova Scotia Utility and Review Board, evaluated the cost recovery provisions of the utility's Load Retention Tariff (LRT) and replacement Extra Large Industrial Active Demand Control Tariff (ELIADC), including the effectiveness of provisions to shield other utility customers from incremental costs of serving load under the tariff.
- Evaluation of proposed modifications of the ERCOT electric power markets intended to support reliability of the system through capacity support mechanisms.
- Assisted the Kansas Corporation Commission Staff in the development of integrated resource plan (IRP) guidelines for analysis and reporting by jurisdictional utilities in Kansas.
- Provided review, analysis and comments in utility IRP development processes in Nova Scotia, Kansas, and Mississippi on behalf of retail regulators.
- Continuing advisory services on behalf of the Mississippi Public Service Commission, addressing issues associated with participation in the MISO RTO, including market design for energy, ancillary services and capacity; benefits assessment; system planning; cost allocation.
- Expert testimony on behalf of Kansas Corporation Commission Staff regarding recovery of costs proposed by the Empire District Electric Company for 600 MW of utility owned wind projects.
- Consulting advisory services evaluating PJM market design and potential modifications to the capacity market and scarcity pricing mechanisms, on behalf of a market participant.
- Affidavits in FERC proceeding (FERC Docket No. ER21-2582-000) on behalf of the Electric Power Supply Association (EPSA) evaluating PJM's proposed modification of the minimum offer price rule (MOPR) applied in the RPM capacity market.
- Expert testimony on behalf of Skipjack Offshore Energy, LLC (Ørsted) before the Maryland Public Service Commission on the estimated economic impacts and retail electricity rate effects associated with Ørsted's applications in Round 2 of Maryland's offshore wind selection process.
- On behalf of the Mississippi Public Service Commission (MPSC), evaluated costs and benefits of Entergy's proposal to join the Midwest Independent System Operator (MISO) regional transmission organization. The analysis included assessment of prior cost-benefit studies as well as independent production cost modeling of the benefits to the Entergy region from joining MISO.
- In support of a major wind farm development in Mexico, conducted a due diligence review of the project PPA price model and its application in projecting project revenues. The evaluation addressed the representation of the renewable energy banking mechanism and the priority lists for allocating project energy and capacity to load centers, and consistency with the CFE interconnection agreement.
- On behalf of the Mississippi Public Service Commission and the Arkansas Public Service Commission, testimony in a complaint at FERC regarding the renewal of sale-leaseback

agreements covering a portion of the Grand Gulf Nuclear Station, addressing potential double collection of costs for plant upgrades.

- On behalf of Mississippi Public Utility Staff, evaluated the proposed acquisition by Entergy Mississippi of the Choctaw Generating Station, an 810 MW air-cooled combined cycle power plant located in Choctaw County, MS. Assessed the utility's economic evaluation of the transaction, the due diligence performed, and the performance history of the plant.
- Expert testimony on behalf of the U.S. government regarding offsets to damages claimed by Alabama Power Company and Georgia Power Company resulting from the Government's partial breach of the spent nuclear fuel "Standard Contract", specifically relating to onsite spent fuel storage costs incurred at the Farley, Hatch, and Vogtle nuclear power plants.
- For the owner of an IPP combined cycle power plant in Mexico, performed an analysis of plant residual value after the expiration of a 25-year PPA with CFE. The valuation applied two distinct methodologies: an "equivalent plant" approach, and a "cost-of-new-entry" approach. Scenarios were conducted for different escalation rates for natural gas prices and capital costs.
- Evaluated competitive impacts from Tucson Electric Power's proposal for utility-owned rooftop solar and community solar. The analysis, in support of testimony before the Arizona Public Service Commission, assessed the status of the competitive market for distributed generation and the likely impacts from proposed utility offerings.
- Developed fuel forecasts for the Mexican power market applied in projecting retail electricity rates and the valuation of renewable energy projects and associated PPAs.
- Testimony on behalf of Catalyst Paper Operations, Inc., presenting an analysis of FERC's market power screens supporting Catalyst's market-based rate application associated with its acquisition of power generating facilities.
- Evaluated the proposed spin-merge of Entergy's transmission assets to ITC Holdings Corp. and advised the Mississippi Public Service Commission on the costs and benefits to Mississippi, including impacts on state regulatory control.
- Quantified effects on New Jersey energy costs of the prospective merger between PSEG and Exelon Corp as part of a comprehensive cost-benefit analysis for the NJ BPU. Effects included wholesale price impacts from changes to nuclear plant availability, direct costs to the state arising from planned staff reductions, and reductions in PSE&G's regulated cost of service arising from estimated merger synergies.
- Affidavit in FERC proceeding (FERC Docket No. ER18-1314-000) on behalf of the Electric Power Supply Association (EPSA) regarding PJM's proposed Capacity Repricing mechanism to modify the PJM capacity market auctions to address state subsidies to certain generating units in PJM.
- Affidavit on behalf of the Electric Power Supply Association in FERC's *Grid Reliability and Resilience Pricing* docket (RM18-1-000). Analyzed market effects of proposed out-of-market subsidy payments to coal and nuclear generating units in ISO/RTO markets.
- Submitted testimony on behalf of Constellation Energy Commodities Group, Inc. in a complaint proceeding before FERC (Docket No. EL07-47-000) regarding the Illinois electricity supply auction. Analyzed the conduct, bidding behavior and outcome of the auction, addressing auction structure and rules, and allegations of market manipulation.
- Conducted economic assessment of KCP&L's proposed $1.2 billion environmental retrofit of La Cygne Generating Station, and testified before the Kansas Corporation Commission on behalf of Commission Staff. Developed analysis framework and key factor inputs for alternative economic assessment and evaluated supporting analyses submitted by KCP&L.

- Directed power market projections and economic benefit analyses in various applications, including: study of economic benefits for the Niagara Power Project (NYPA); cost-benefit analysis of environmental protection alternatives related to fueling of Salem Generation Station (PSE&G) and Indian Point Nuclear Power Plant (Entergy) and to the operation of Danskammer Point Generating Station (Dynegy).
- Submitted testimony at FERC on behalf of the Mississippi Public Service Commission regarding the allocation of settlement benefits among the Entergy operating companies. The testimony quantified shortfalls in benefits owed to Entergy Mississippi related to a settlement by Entergy resolving damage claims from a coal transportation disruption that restricted output at two of Entergy's generating plants.
- Conducted independent validation of Southern California Edison's (SCE) internal power supply risk assessment model, including the model's theoretical underpinnings, implementation, and interpretation of outputs. The SCE model assesses procurement cost risk based on stochastic simulation that accounts for dispatchable resources, supply contracts, power forward and gas forward positions.
- Calculated damages and submitted expert testimony on behalf of PG&E, SCE and SDG&E in separate cases before the US Court of Federal Claims and Los Angeles Superior Court regarding unresolved claims stemming from energy sales by defendants into the PX and ISO markets during the California energy crisis.
- Developed RFP documents and evaluation procedures for the Ontario Ministry of Energy's 2500MW RFP. Directed the economic evaluation of generator proposals, including development of models used to estimate energy market revenues and contingent capacity support payments, and created analytical tools to evaluate aggregate costs, including transmission upgrade cost impacts, for every possible portfolio of submitted bids.
- Developed probabilistic risk management model for market price forecasting, asset valuation and power supply cost analysis. Adapted and implemented the model in applications for Oglethorpe Power Corporation (OPC), Central Maine Power Company, Vermont Yankee Nuclear Power Corporation, Commonwealth Electric Company, and Connecticut Yankee Atomic Power Company. Analyses included forecasting market clearing energy and capacity prices, and estimating hedge values for retained capacity, new unit construction, power supply bids, and financial derivatives.
- Evaluated power supply proposals for short-term and long-term RFPs by OPC, directing and assessing PROMOD scenarios for alternative supply portfolios. Created and applied an independent price forecasting model and Monte Carlo analysis to evaluate risk profiles of supply alternatives.
- Provided analytical support for RFP design and portfolio evaluation in the Ireland 500 MW capacity procurement.
- Assisted the development and implementation of BG&E's solicitation of standard offer supply service. Estimated market energy and capacity prices in a 15-year forecast applying a proprietary linear programming/optimal system expansion model.
- Served as testifying expert and produced expert report for OPC in arbitration proceedings between OPC and LG&E Power Marketing (LG&E) regarding LG&E's valuation of coal supply contracts associated with a long-term power purchase and sale agreement.
- Evaluated the Public Service Company of Oklahoma's 2008 Supply Side RFP in support of testimony for a potential bidder. Assessed bid evaluation methodology, credit and collateral requirements, and implementation of debt equivalence adjustments.

- Managed the Data and Rate Design Committees and Backup Bidding Team for the annual auctions of New Jersey Basic Generation Service (BGS). Participated in development of auction process, rules and protocols, and regulatory filings. Directed bidder information procedures and auction Data Room Team. Conducted PJM wholesale market price assessment to determine starting prices for the descending clock auction.
- Conducted benefits analysis of proposed hydroelectric power plant development in New York State, including reliability benefits, environmental benefits and wholesale market price impacts.
- Directed economic analyses and produced white papers on the economic benefits of baseload generation from nuclear power plants on behalf of Exelon Corporation. Benefit analysis examined impacts on wholesale market prices, and peak hour power flow impacts. (Separate assignments for 5 nuclear plants: Oyster Creek, Limerick, TMI, Peach Bottom, and proposed restart of Zion).
- On behalf of Occidental Chemical Corporation, evaluated proposed changes to cost allocation methods in the Entergy production cost sharing mechanism, in support of testimony in FERC proceeding (Docket No. ER07-682-000). The evaluation estimated the impact on the individual Entergy operating companies and assessed compliance with regulatory accounting principles.
- Evaluated PJM proposals to modify OATT allocation of cost responsibility for transmission upgrades under the Regional Transmission Expansion Plan (RTEP), supporting testimony in FERC Docket EL07-57-000 (Consolidated).
- Advised the Ontario Power Authority in generator contract dispute arising from rule modifications by the Independent Electric System Operator (IESO). Provided assessment of background and intent of contract payment mechanisms and preliminary analysis of revenue impacts of rule changes on generator counterparties.
- Submitted testimony before FERC on behalf of the MPSC regarding Entergy Louisiana’s proposal to allocate cancelation costs of the Little Gypsy Repower Project through the Entergy Service Agreement’s rough production cost equalization mechanism.
- Developed forecast model of the CFE (Mexican electric utility) short-run cost of generation (CTCP) in support of the acquisition of a large-scale wind project in Oaxaca, México. The model allowed for evaluation of potential project revenue impacts associated with increased gas-fired and renewable generation on the CFE system.
- As an advisor to a major capital finance entity, evaluated the project financial model for a proposed hydroelectric generation project in western Mexico. The model review considered representation of the renewable energy banking mechanism under Mexican energy regulation, representation of seasonal production and demand patterns, and the associated projection of profit and loss and debt service coverage of the life of the project.
- Conducted detailed valuation analysis of qualifying facility (QF) hydro plants for New York State Electric & Gas Corporation (NYSEG), supporting settlement negotiations with plant owners. The analysis considered the value to NYSEG of buying out the contracts or assuming ownership under expected default by the plant owners.
- Conducted assessment of potential effects on wholesale markets and default service procurement of the proposed merger of Exelon Corp. and Constellation Energy Group Inc., in support of testimony submitted to the Maryland Public Service Commission on behalf of Commission Staff.
- Evaluated power market modeling employed by a party in a major supply contract litigation. Evaluated the party’s application of PROMOD and MIDAS models used to value the transaction, and associated risk analyses used to assess value at risk (VaR). Identified substantive errors in inputs, contemporaneous market assumptions, risk analysis and economic inference.

- Conducted due diligence assessment of the financial modeling of off-taker PPA revenues for the 396MW Mareña wind power project in southern Mexico, including the representation of off-taker priority list weighting and energy banking under CRE renewable interconnection rules.
- Conducted valuations of all Central Maine Power (CMP) power plants, supporting negotiated sale of generation assets to FPL. Applied market price forecasts and extensive monte carlo analyses to examine multiple transaction scenarios, including the value of retaining hydroelectric facilities as a supply hedge during the transition to competition. FPL Energy agreed to pay $845 million for all of CMP's non-nuclear generating assets.
- Produced power plant valuation of the TNP One lignite-fueled unit for Texas-New Mexico Power Company to support asset sale strategy as well as litigation with respect to stranded costs.
- Directed power market price forecasts for multiple clients, applying proprietary linear programming model to evaluate optimal capacity expansion for fuel price, demand growth and technology scenarios.
- Provided consulting assistance to the US Department of Justice in defending claims related to spent nuclear fuel breach of contract in *Vermont Nuclear Power Corporation, and Entergy Nuclear Vermont Yankee, LLC et al., v. The United States* in the United States Court of Federal Claims (Nos. 02898C & 03-2663C) and *Portland General Electric Company et al., v United States of America* in the United States Court of Federal Claims (No. 04-0009C).
- Assessed the benefit-cost evaluation methods and assumptions applied to the 2010-12 energy efficiency plans in Massachusetts, for the Office of the Attorney General of Massachusetts.
- Conducted extensive analyses for a California IOU in refund proceedings related to the California energy crisis. Examined impacts of the calculation and application of mitigated market clearing prices (MMCPs) in the determination of refunds owed by generators selling into the California markets.
- For Baltimore Gas & Electric (BGE) testimony before the Maryland Public Service Commission, estimated rate impacts for alternative supply scenarios. Conducted power market analysis, estimation of wholesale market impacts on retail supply auction results, and self-build generation analysis.
- Estimated benefits of competition in electric markets through four empirical analyses and quantified the dollar benefits to Maryland consumers of wholesale competition in PJM and state retail restructuring.
- Developed economic analysis of PJM transmission cost allocation proposals for merchant transmission entity. Supported testimony filed at FERC in Docket No. ER06-880-000, et al.
- Directed the evaluation of the benefit-cost ratio methodology used to validate energy efficiency measures in Massachusetts.
- Evaluated PJM price formation, demand responsiveness, and DR compensation proposals for comments submitted on FERC's ANOPR on "Wholesale Competition in Regions with Organized Electric Markets" (Docket Nos. RM07-19-000 and AD07-7-000).
- Performed strategic consulting work for BGE. Prepared expert testimony submitted in Maryland electric utility restructuring proceedings and consulted on utility regulatory strategy. Addressed market impact and economic rationale of competition policy, strategic aspects of asset disposition, stranded cost recovery, and retail access.
- Consulted on asset valuation alternatives and stranded cost recovery strategy, including the application of an auction appraisal of generation assets, for Niagara Mohawk Power Corporation.

- Directed study reviewing current methods of load profiling for retail settlement and energy imbalance services in the U.S. and Canada. The work was included in a series of load profiling studies for Japan's Ministry of Economy, Trade, and Industry.
- For ISO-NE, the NYISO and PJM Interconnection, in the evaluation of the proposed centralized resource adequacy model (CRAM): assessed capacity cost recovery for varied market conditions and implications for timing and frequency of capacity auctions.
- Conducted an analysis of reserve margin impacts on energy price volatility in the development of a power supply procurement process for Acquirente Unico, the Italian electric market single buyer.
- Directed analysis of optimal market hedge ratios by customer class for Dayton Power and Light. Analysis examined risk exposure due to price-driven customer migration under proposed retail access program.
- Produced pro forma valuation for the non-nuclear portion of the Connecticut Yankee nuclear site. Study considered unique site value and costs for a new generating plant, project financing costs, and the future competitive environment including market energy and capacity prices.
- Served as testifying expert on market modeling before the Massachusetts Department of Telecommunications and Energy on behalf of Commonwealth Electric. Testimony supported analysis of Commonwealth Electric's stranded costs and buyout options for legacy power purchase agreements.
- Directed new coal generation feasibility study for proposed investment in the Four Corners region of New Mexico. The analysis included market demand, competing supply, availability and cost of electrical transmission, cost and deliverability of coal, availability of water, and environmental concerns.
- Conducted a comprehensive review of the retail access experience in New England states. Developed state-by-state profiles that outlined the regulatory regime, transition period, standard-offer and default-service provisions. Evaluated end-user and supplier exposure to variable market prices.
- Provided consulting services to Niagara Mohawk Power Corporation on the modeling of transaction value for outsourcing standard offer service.
- Evaluated the competitive market of potential suppliers for PSE&G's auction of standard offer supply.
- Advised on the theoretic foundations of economic cost concepts and regulatory applications in avoided cost cases for a group of northeast electric utilities.
- Evaluated measures of competitiveness in present and future wholesale power markets and developed several models for use in assessing forward product prices for a large U.S. public power company.
- Participated in power purchase prudence analyses for PG&E, Nevada Power Company, Texas New Mexico Power Company, and Public Service Company of Colorado.

Other professional experience

Prior to joining Bates White, Mr. Cain served as a Consultant at National Economic Research Associates (NERA). In this position, he conducted a variety of power sector analyses in NERA's energy practice. Mr. Cain also served as an Economist with Jones Lang Wootton USA, where he directed economic research and market analysis for a range of corporate clients. Previously, Mr. Cain was a Consultant with Apogee Research, where he conducted economic impact analyses, and participated in a variety of transportation and environmental economics consulting assignments.

Expert testimony

- On behalf of Chiltepin Solar-Storage, LLC, *Trane Technologies Company LLC vs Chiltepin Solar-Storage, LLC et al*, New York Supreme Court (Index No. 651227/2024). Expert rebuttal report.
- On behalf of Electricidad Aguila de Tuxpan, International Court of Arbitration, International Chamber Of Commerce, Arbitration No. 27839/PDP. Expert reports, live testimony at arbitration hearing.
- On behalf of PSEG Renewable Transmission LLC, in Maryland Public Service Commission Case No. 9773. Written direct testimony.
- On behalf of the Data Center Coalition, *In the Matter of Pacificorp, dba Pacific Power, Request for General Rate Revision* (OPUC Docket No. UE 433). Written direct testimony.
- On behalf of ALLETE Clean Energy, Inc., *Caddo Wind, LLC v. Hormel Foods Corporation* (JAMS arbitration). Expert Report, live testimony at hearing.
- On behalf of the Staff of the Kansas Corporation Commission, IMO Application of The Empire District Electric Company for the Commission to Make Certain Changes in its Charges for Electric Service (KCC Docket No. 21-EPDE-444-RTS). Written testimony.
- On behalf of Skipjack Offshore Energy, LLC, in Maryland Public Service Commission Case No. 9666. Written direct, supplemental direct, and rebuttal testimonies; live testimony at hearing.
- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER21-2582-000). Affidavit and supplemental affidavit.
- On behalf of the Mississippi Public Utility Staff, in Mississippi Public Service Commission Docket No. 2018-UA-267. Written testimony.
- On behalf of the Mississippi Public Utility Staff, in Mississippi Public Service Commission Docket No. 2018-UA-204. Written testimony.
- On behalf of the Mississippi Public Service Commission and the Arkansas Public Service Commission, *Louisiana Public Service Commission v. System Energy Resources, Inc., and Entergy Services, Inc.*, Federal Energy Regulatory Commission (Docket No. EL18-152-000). Written testimony.
- On behalf of Producers of Renewables United for Integrity Truth and Transparency supporting Motion for Stay of Agency Action filed against the EPA, in the U.S. Court of Appeals for the D.C. Circuit. Expert declaration.
- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER18-1314-000). Affidavit.

- On behalf of Petitioners-Plaintiffs (Hudson River Sloop Clearwater, Inc., and others) in New York State Supreme Court (Index No. 07242-16). Affidavit.
- On behalf of the Electric Power Supply Association, *Calpine Corporation v. PJM Interconnection, L.L.C.*, FERC (Docket No. ER16-49-000, *et al.*). Affidavit.
- On behalf of the United States, *Alabama Power Company and Georgia Power Company v. The United States*, in the U.S. Court of Federal Claims (No. 14-167C and No. 14-168C). Expert report; live testimony.
- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER18-1314-000). Affidavit.
- On behalf of the Staff of the Kansas Corporation Commission, *IMO the Petition of The Empire District Electric Company for Approval of Its Customer Savings Plan* (KCC Docket No. 18-EPDE-184-PRE). Written testimony.
- On behalf of the Electric Power Supply Association, *Grid Reliability and Resilience Pricing*, FERC (Docket No. RM18-1-000). Affidavit.
- On behalf of Calpine Corporation and NRG Energy, Inc., Application of Centerpoint Energy Houston Electric, LLC to Amend a Certificate of Convenience and Necessity for a Proposed 345-kV Transmission Line (…), Public Utility Commission of Texas (Docket No. 473-15-3595). Written testimony; live testimony at hearing.
- On behalf of Catalyst Paper Operations, Inc., *Catalyst Paper Operations Inc.*, FERC (Docket No. ER15-794-002). Written testimony.
- On behalf of the Mississippi Public Service Commission, *Entergy Services, Inc.*, FERC (Docket No. ER13-432-002). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company and the State of California, *Pacific Gas and Electric Company and Southern California Edison Company v. United States; San Diego Gas & Electric Company v. United States*, in the US Court of Federal Claims (No. 07-157C and No. 07-167C, Consolidated; No. 07184C). Written testimony; deposition testimony.
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services, Inc., et al.*, FERC (Docket No. EL09-61-004). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services Inc., et al.*, before the FERC (Docket Nos. ER12-1384, *et al.*). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, *Electric Refund Cases,* in the Superior Court of the State of California (Judicial Council Coordination Proceeding No. JCCP 4512). Written testimony; deposition testimony.
- On behalf of the Staff of the Kansas Corporation Commission, IMO the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239, before the Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE). Expert report; live testimony at hearing.
- On behalf of Constellation Energy Commodities Group, Inc., *The People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, et al*., FERC (Docket No. EL07-47-000). Affidavit.

- On behalf of Oglethorpe Power Corporation, in contract dispute brought by LG&E Energy Corp. and LG&E Energy Marketing, Inc. (CPR Arbitration proceeding). Expert report; deposition testimony; live testimony.
- On behalf of Commonwealth Electric Company, Petition of Cambridge Electric Light Company and Commonwealth Electric Company requesting approval of their Transition Charge Reconciliation Filing, before the Massachusetts Department of Telecommunications and Energy (Docket No. DTE 99-90). Live testimony.

Publications and presentations

- "Renewable Natural Gas Supply and Demand for Transportation" White paper (June 2019).
- "Biodiesel Distribution in the US and Implications for RFS2 Volume Mandates" (July 2016).
- "Clean Energy Certificates: The Key to Renewable Energy Financing," with Nicolás Puga. Electricity Future Forum Mexico 2014 (November 2014).
- "Evaluation of the Entergy Mississippi Proposal to Join MISO," Report to the Mississippi Public Service Commission. (August 2012, Revised)
- "Beyond Loan Guarantees: Fostering U.S. Nuclear Investment in a Post-Fukushima World," with Glenn George. Conference paper and presentation, Center for Research in Regulated Industries 30th Annual Eastern Conference. Skytop, PA (May 2011).
- "Retail Rate Comparisons and the Electric Restructuring Debate," with Jonathan Lesser. Bates White briefing paper, 2008-E-11-01. (November 2008).
- "Economic and System Reliability Benefits of the Three Mile Island Generating Station," with Spencer Yang and Jonathan Lesser. White paper (April 2008).
- "Trends in Electricity Deregulation." Conference presentation at DTN/Meteorlogix Energy Summit. Minneapolis (June 2008).
- "A Common Sense Guide to Wholesale Electric Markets," with Jonathan Lesser. White paper (April 2007).
- "Utility Mergers: The Exelon-PSEG Merger." Workshop presentation, Market Power, Mergers, and Governance, Center for Research in Regulated Industries. Newark (January 2007).
- "The Fallacy of High Prices," with Howard Axelrod and David DeRamus. Public Utilities Fortnightly 144 (November 2006).
- "Nuclear Power in Future Electric Rate Cases." Conference presentation, Managing the Modern Utility Rate Case, Law Seminars International. Las Vegas (February 2006).
- "Applications of Probabilistic Price Modeling." Workshop presentation, Marginal Cost Working Group. Washington, DC (September 2004).

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SONGHOON (SPENCER) YANG, PHD

Principal

AREAS OF EXPERTISE

- Reliability analysis
- Power flow analysis
- Renewable energy development
- Economic due diligence
- Electricity market analysis
- Generation portfolio analysis
- Energy policy and regulation

Summary of experience

Dr. Yang is a Principal in the Bates White Energy Practice. He has provided expert testimony and advised clients on reliability analysis, power flow analysis, renewable energy development, economic due diligence, electricity market analysis, generation portfolio analysis, energy policy and other regulatory matters. He has extensive experience developing reliability and power flow models and has applied these models to assess the reliability and cost impacts of proposed changes to the power system, to value the costs and benefits of adding renewable energy generation into a portfolio of fossil fuel generation, and to develop supply and demand resources to optimize reliability, energy security and climate change mitigation.

Spencer has served as a co-chair of the Renewable Energy Committee for former South Korean President Moon Jae-In in developing South Korea's Energy Transformation Plan (providing a transition to a sustainable energy system). He has also advised both US and Korean IPPs in developing renewable energy projects; he has advised major US solar QF developers on QF interconnection and PPA issues; he has evaluated value of solar and net metering issues; he has evaluated solar PPAs on behalf of state regulators; he has advised private equity funds on utility mergers; and he has analyzed the benefits of adding renewable generation into a portfolio of fossil fuel generation on behalf of Airtricity, the European Investment Bank, and the California Energy Commission. He consulted the California Energy Commission in establishing the feed-in tariff and 33% RPS in 2006-2007. He was also a member of the Electricity Policy Review Committee in South Korea, where he was responsible for reviewing and approving national electricity policies, energy mix objectives, and integrated resource plans. He is currently an advisor to a developer of solar and storage projects in Africa and to an acquirer/developer of renewable energy projects in the Americas.

Spencer has served as both a testifying and consulting expert in a wide array of cases, including the Exelon–Constellation merger, value of solar analysis, generation interconnection analysis, economic due diligence, FERC PURPA section 210(m) proceedings, applications for market-based rate authority, reliability needs assessments of transmission lines, the potential impact of the retirement of nuclear generation facilities, an assessment of global nuclear power plant construction and decommissioning services, analysis of global shipbuilding industry, various proceedings before federal and state regulatory commissions and civil damages cases.

Spencer received a PhD in High Energy Physics from Columbia University and two additional graduate degrees from Columbia University, a Master of Philosophy in High Energy Physics and a Master of Arts in Physics. Prior to joining Bates White Economic Consulting, he served as a Postdoctoral Scholar, Senior Postdoctoral Scholar, and Staff Scientist at California Institute of Technology, Visiting Scholar at Stanford University and Visiting Fellow at Sussex Energy Group – SPRU – University of Sussex – Brighton, UK.

Education

- PhD, High Energy Physics, Columbia University
- MPhil, High Energy Physics, Columbia University
- MA, Physics, Columbia University

Selected energy consulting experience

- Served as an energy policy advisor and co-chair of the Renewable Energy Committee for former South Korean President Moon, which was responsible for developing South Korea's Energy Transformation Plan.
- Served as a member of the South Korean Electricity Policy Review Committee, reviewing and approving national electricity policies, energy mix objectives, and integrated resource plans.
- Serving as an economic advisor to major Korean utility and global IPP, in developing and acquiring renewable energy projects in the Americas.
- Serving as a market advisor to a US–Zambia joint venture in developing solar plus storage projects in Zambia and Africa.
- Providing consulting services to U.S. Department of Justice (DOJ) in multiple confidential matters.
- Provided consulting services to Ministry of Trade, Industry and Energy (MOTIE) of South Korea on global new shipbuilding market assessment and outlook.
- Provided consulting service to State of Texas in *State of Texas v. Meta Platforms, Inc. fka Facebook, Inc.* and quantified the extent to which Facebook applied facial recognition technology to images of Texas residents in connection with alleged violations of the Texas Capture or Use of Biometric Identifier ("CUBI") Act and Deceptive Trade Practice Act ("DTPA").
- Served as a consulting expert to a major renewable energy developer on issues associated with interconnecting solar PV Qualified Facilities to the U.S. transmission system.
- Provided consulting services to MOTIE on global and domestic nuclear power plant construction and decommissioning market assessment and outlook.
- Provided consulting services to major Korean IPPs on forming solar project joint ventures, asset purchases and sales, land leases, permits, interconnections, power marketing, and PPA negotiations.

- Provided consulting services to major Korean conglomerates regarding the US solar market outlook and business development opportunities.
- Provided consulting services to the Korea Development Institute (KDI) on issues related to Korea's electricity market reform, transmission investment, and generation investment.
- Provided consulting services to California Energy Commission in developing the 33% Renewable Portfolio Standard (RPS) goals, Market Price Referent (MPR), and Feed-in Tariff (FiT) mechanism.
- Provided consulting services to a major US private equity fund related to the Duke–Progress merger.
- Conducted generation portfolio analysis on behalf of Airtricity, EIB, and CEC, quantifying the benefits and costs of adding renewable generation into a conventional fossil fuel generation portfolio mix.
- Analyzed and evaluated solar PPAs on behalf of the Mississippi Public Utility Staff, providing independent economic and risk analyses of the facilities proposed in the petitions for Certificates of Public Convenience and Necessity (CPCN) to construct, operate, and maintain solar generating facilities.
- Conducted analysis on behalf of the Mississippi Public Service Commission, quantifying the benefits and costs of adding the Kemper IGCC plant into the Mississippi Power generation mix.
- Conducted PROMOD benchmarking analysis on behalf of MISO to improve the transmission planning and transmission congestion modelling process.
- Conducted a full production cost modeling study on behalf of the New York Regional Interconnect, Inc. (NYRI) related to NYRI's application to the New York PSC to construct a 1200-MW HVDC transmission line.
- Conducted reliability studies on behalf of Exelon Corporation related to the potential retirement of the Zion, Limerick, Three Mile Island, and Oyster Creek nuclear generation stations. Performed Optimal Power Flow and Security-Constrained Optimal Power Flow studies.
- Submitted an advisory report to the KDI related to the relationship between generation and transmission investment, how major US markets deal with investment and pricing of transmission assets and modeling the complex interactions between generation and transmission investments.
- Submitted consultant reports to the CEC related to the proper calculation of California's renewable energy market price referent (MPR), development of a feed-in tariff, and generation portfolio planning for its 2007 Integrated Energy Policy Report.
- Submitted an article to the European Investment Bank related to the development of efficient electricity portfolios for Europe that maximize energy security and climate change mitigation.
- Submitted a report to Airtricity related to the role of wind and other renewables in enhancing Ireland's energy security and diversity. Applied a mean-variance portfolio optimization technique to Ireland's generating mix.
- Submitted a report to Airtricity related to the estimation and valuation of portfolio instruments for Airtricity Scotland. Accommodated wind generation in portfolio optimization and hedging for Scotland and the UK's electric power sector.
- Submitted a report to the Center for Research in Regulated Industries regarding obstacles to and major determinants of efficient transmission investment in the United States.

Prior expert witness engagements

- Testified on behalf of OG&E and Western Farmers in the FERC proceeding related to the determination of whether the PEC Facilities qualify as transmission for rate recovery under the SPP Tariff (FERC Docket No. ER22-1525)
- Testified on behalf of Vote Solar in State of Utah proceeding related to net metering and value of distributed generation export credit rate (Docket No. 17-035-61).
- Testified on behalf of Calpine and NRG regarding certificates of public convenience and necessity to construct the Houston Import Project (SOAH Docket No. 473-15-3595).
- Testified on behalf of Maryland PUC Staff regarding potential market power issues associated with the proposed Exelon–Constellation merger (Case No. 9271).
- Testified on behalf of Virginia State Corporation Commission Staff regarding certificates of public convenience and necessity to construct a 500-kV transmission line (Case Nos. PUE-2007-00031 and PUE-2007-00033).
- Testified on behalf of Shell Trading Gas and Power Company in FERC proceedings associated with Southern Company's market-based rate application (Docket No. EL04-124, et al.).
- Submitted testimony on behalf of Newport Associates in New Jersey District Court related to the resilience value of restoring the B&C Lines, which interconnect New Jersey and New York City (Case No. 16-cv-08445).
- Submitted testimony on behalf of Vote Solar in State of Utah proceeding related to net metering and value of distributed generation export credit rate (Docket No. 17-035-61).
- Submitted testimony on behalf of Ecoplexus in State of Oregon proceeding related to solar QF interconnection issues (Docket No. 2009).
- Submitted testimony in *The State of Mississippi v. Entergy Mississippi, et al.*, quantifying imports from off-system suppliers into Entergy's transmission system, in the Southern District Court of Mississippi (Civil Action No. 3:08cv780-CWR-LRA).
- Submitted affidavit on behalf of Occidental Chemical Corporation in FERC proceedings related to the PURPA section 210(m) case (Docket No. QM14-3-000).
- Submitted testimony on behalf of CPV Maryland and CPV Shore in FERC proceedings related to their market-based rate applications (Docket Nos. ER13-___).
- Submitted testimony in *David Jenkins v. Entergy Corp.*, quantifying imports from off-system suppliers into Entergy's transmission system, in the District Court of Chambers County, Texas (Cause No. 20666).
- Submitted testimony on behalf of Cottonwood Energy in state regulatory proceedings regarding certificates of public convenience and necessity to construct a 345-kV transmission line in Texas (Docket No. 34611).
- Submitted testimony on behalf of Occidental Chemical Corporation in FERC proceedings related to the reliability of the Tres Amigas project (Docket No. ER10-396-000).
- Submitted testimony on behalf of Occidental in FERC proceedings related to the physics of electricity flows and the "commingling" of electric energy (Docket No. EL10-22-000).
- Submitted testimony on behalf of Shell Trading Gas and Power Company in FERC proceedings related to Southern Company's updated market-based rate application (Docket No. ER96-780).
- Submitted testimony on behalf of Shell Trading Gas and Power Company in FERC proceedings related to the proper quantification of Simultaneous Import Capability into the Southern Company Balancing Authority Area (Docket No. EL04-124, et al.).

Publications

- Yang, Spencer, and Shimon Awerbuch. “Efficient Electricity Generating Portfolios for Europe: Maximizing Energy Security and Climate Change Mitigation.” In *Analytical Methods for Energy Diversity & Security: Portfolio Optimization in the Energy Sector*: *A Tribute to the Work of Dr. Shimon Awerbuch*, edited by Morgan Bazilian and Fabien Roques, Chapter 5. London: Reed Elsevier, 2008.
- Dr. Yang has published numerous high energy physics papers in peer-reviewed journals, such as *Physical Review Letters* and *Zeitschrift für Physik*.

Awards and honors and fellowships

- Recipient, AKPA Outstanding Young Researcher Award (Honorable Mention).
- Recipient, DESY International Outstanding PhD Award.
- Recipient, Columbia University Graduate Fellowship.

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NICOLÁS PUGA, MSC

Senior Engineering Advisor

AREAS OF EXPERTISE

- Utility resource planning
- Power generation modeling
- Transmission planning
- Renewable energy development
- Distribution reliability
- Demand-side management
- Energy policy and regulation

Summary of experience

Nicolás Puga has more than 40 years of experience as engineering and economics advisor to electric utilities, generation and transmission companies and regulatory agencies in the analysis of electric power and natural gas markets, utility resource supply planning, generation and transmission project development and distribution system modernization and hardening. Mr. Puga has conducted technology and market risk assessments in due diligence of utility-scale solar and wind energy generation project financing and advised state utility regulators on various aspects of distributed energy resource development. He currently advises clients on utility scale battery energy storage facility development and utility distributed storage deployment planning. Mr. Puga has testified as an expert in the planning and cost of transmission lines and power plant certification and abandonment proceedings in California, Kansas, New York, Texas, Virginia, West Virginia and at the Federal Energy Regulatory Commission.

Education

- MSc, Energy Systems Engineering, University of Arizona
- BSc, Electrical Engineering, Universidad de Guanajuato, Salamanca, México

Professional experience

- Bates White Economic Consulting, Washington, DC
  - Affiliate, 2026–present
  - Partner, 2008–2025
  - Principal, 2007–2008

- Energy Advisor, Navigant Consulting, Inc., Washington, DC, 2005–2007
- Director General, Navigant Consulting de México, Navigant Consulting, Inc., 2003–2005
- Director, International Management Consulting Services, Navigant Consulting, Inc., Washington, DC, 1999–2003
- Resource Management International, Inc.
  - Senior Vice President, Washington, DC, 1999
  - Vice President, Resource Planning Division, Manila, Philippines, 1996–1998
  - Vice President, Demand-Side Management, Sacramento, CA, 1991–1995
- Vice President, Demand-Side Management, ANCO Engineers, Inc., Culver City, CA, 1984–1991
- Research Associate, University of Arizona, Department of Nuclear and Energy Engineering, Tucson, AZ, 1981–1984
- Research Engineer, Alternative Sources of Energy Division, Instituto de Investigaciones Eléctricas, Cuernavaca, México, 1976–1980
- Design Engineer, Special Projects, Comisión Federal de Electricidad, Celaya, México, 1975–1976

Selected industry, government, and business consulting experience

Regulatory and litigation support

- Expert testimony on behalf of Kansas Corporation Commission Staff regarding recovery of costs proposed by the Empire District Electric Company for 600 MW of utility owned wind projects.
- Testified before FERC in Southwest Power Pool, Inc., Docket No. ER18-99-005 on behalf of the group of transmission owners and transmission dependent cities in SPP to contest the appropriateness and accuracy of applying the analytical methods used by a transmission asset owner to quantify and allocate powerflow based benefits and costs of those assets to load.
- Submitted testimony in FERC Southwest Power Pool, Inc. GridLiance High Plains LLC, Dockets No. ER18-2358-001 and No. ER19-1357-000 (consolidated) on behalf the Southwestern Public Service Company to show that the analyses introduced by Gridliance High Plains' witnesses relied on inappropriate methods to answer the questions raised in that proceeding, and that those methods are not capable of producing the information that GHP's witnesses claimed to rely on to arrive at their conclusions.
- Review and analysis of annual transmission and distribution expansion and modernization programs by Entergy Mississippi (EML) on behalf of the Mississippi Public Utility Staff (Years 2016, 2017, 2018, 2019, 2020 and 2021). The utility's most recent grid modernization programs include systematic replacement and hardening of aging T&D infrastructure, system-wide deployment of Advanced Metering Infrastructure (AMI) and experimental deployment of smart technology; such as self-healing distribution networks in selected distribution system areas.
- As a technical and economic advisor to the Mississippi Public Service Commission, ongoing analytical and policy support to the MPSC in MISO and OMS Committees and transmission planning and cost allocation Working Groups. Provided inputs on the performance, costs and

expected growth of Distributed Energy Resources, including BES, in the MISO supply mix. The work involves attending technical meetings, conducting research and analysis on transmission planning and distributed energy resources, participating in stakeholder discussions and interacting with MISO's planning staff and external advisors to convey and support the position of the MPSC.

- Directed the development and implementation of a cost estimation system for high voltage transmission infrastructure for a regional transmission organization.
- Expert testimony on behalf of the Kansas Corporation Commission Staff regarding the proposed acquisition of 800 MW of wind generation by Empire District Electric Company. Testimony addressed the implications of unaccounted for wind farm performance risk in the economic analysis of the proposed acquisition and long term ownership of several wind farm projects, and how this concern, prevalent in the U.S. wind industry, has historically been mitigated by protections built-into Power Purchase Agreements.
- On behalf of the Maryland Energy Administration, provided expert consultation to the Maryland Grid Resiliency Task Force in assessing the need to harden the electric distribution infrastructure and improve the storm response of Maryland's distribution utilities. Contributor to the report of the Task Force's work titled "Weathering the Storm" published by the Office of Governor Martin O'Malley in compliance with Executive Order 01.01.2012.15.
- Reviewed the grid modernization plan of an Illinois distribution utility authorized under the Energy Infrastructure Modernization Act (EIMA) of 2011. Evaluated the uncertainties in achieving the intended effect of infrastructure investments, including gradual deployment of advanced metering infrastructure, on reliability metrics and customer benefits. The analysis involved statistical analyses and simulations of its distribution system reliability during storms to assist the company in prioritizing distribution areas for improvements.
- Reviewed several Maryland distribution utility system hardening plans guided by IEEE reliability indexes and proposed modifications to several IEEE Standard reliability metrics to better focus on long duration outages.
- Participated in various working groups in regional transmission organizations and ISOs (CAISO, PJM, MISO) addressing methodological and procedural improvements to annual transmission expansion planning processes.
- Participated in MISO stakeholder discussions, along with distribution utility planners and state regulatory commissions' staff to discuss an implementation path regarding IEEE Std 1547-2018 right-through requirements within the MISO region. The stakeholder discussion included a workshop and several conference calls co-facilitated by MISO and EPRI.
- Reviewed the forecasting and fuel planning processes and procedures of Nova Scotia Power, Inc. as part of an audit of Nova Scotia Power, Inc.'s fuel and electric power purchases and sales, on behalf of the Nova Scotia Utility and Review Board.
- Advisor to the Mississippi Public Service Commission in state regulator working groups assessing the capacity benefit metrics of new transmission towards lowering the Planning Reserve Margin used in establishing Resource Adequacy in MISO.
- Retained by an independent power producer in México as subject matter expert in an international arbitration proceeding subject to the International Court of Arbitration of the International Chamber

of Commerce. The subject of the dispute involves the payment for damages claimed by the Comisión Federal de Electricidad (CFE) resulting from an alleged contract breach related to the IPP failure to maintain the generating facility's demonstrated capacity during a certain period of time.

- Expert witness on behalf of Mississippi Public Service Commission in *Louisiana Public Service Commission v. Entergy Services, Inc.* (FERC, Docket No. EL11-57-002), on the appropriate treatment of power plant cancelation costs under the Entergy System Agreement (ESA).
- On behalf of the Mississippi Public Service Commission, led a team of experts in electric power markets in an independent evaluation of the benefits to Mississippi electricity consumers derived from Entergy joining the Midwest ISO.
- Led a team of experts in economics, power plant emissions control, and power market modeling in the evaluation of the economic feasibility of retrofitting the LaCygne coal-fired generating facility, an aging coal fired generating plant in Kansas, to meet recently adopted and proposed environmental regulations. Testified in front of the Kansas Corporation Commission on the key assumptions and uncertainties driving the future prices of natural gas and low-sulfur western coal which that will likely determine the long-term future competitiveness of coal fired plants.
- Evaluated technical aspects of the proposed spin-merge of Entergy's transmission assets to ITC Holdings Corp. and advised the MPSC on alternative paths to achieve the same planning and operational excellence claimed to be achievable only through the proposed transaction.
- Testimony on behalf of the Virginia State Corporation Commission Staff about the use of Smart Meters in a utility Conservation Voltage Reduction (CVR) program designed to reduce electric distribution losses and to conserve energy at customer facilities. The analysis compared the cost of relying on Advance Metering Infrastructure to that of traditional CVR technology.
- Expert witness in the independent reliability needs assessment and economic impact analysis for the proposed 765kV Potomac Allegheny Transmission Highline (PATH) for the Public Utility Commission of West Virginia (ongoing).
- Served as expert witness appearing in licensing proceedings of the New York Public Service Commission (NYPSC) with respect to the application of New York Regional Interconnect, Inc. (NYRI) to construct and maintain a 190-mile, 1,200-MW HVDC transmission line. The main focus of the testimony was the inferiority of energy efficiency and demand-response programs as a fully equivalent alternative to the proposed transmission line, and the line's ability to bring upstate NY wind generation to the Hudson Valley and NYC.
- Managed the independent reliability needs assessment of the proposed 265-mile 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500 kV Transmission Line for the Virginia State Corporation Commission. The work involved load flow modeling of multiple transmission, generation, and demand response alternatives scenarios capable of reliably serving the forecast load. Prepared and presented testimony as to the ability of PJM's RPM demand response programs to provide the same level of long-term reliability as that of the proposed line.
- In preparation of expert testimony in a FERC market power proceeding, studied alternative approaches used for the optimal economic scheduling of hydroelectric facilities under conditions that require significant departures from historical dispatch patterns and hard constraints on terminal reservoir conditions in order to maximize the value of the hydro resource.

- Analyzed the necessary conditions to deliver renewable energy from Northern Baja California, México to California, evaluating the status of existing and anticipated energy infrastructure on the México side of the border. Developed growth projections and analyzed energy infrastructure options for Baja California, including the potential for development of renewable energy generation, treatment of out-of-country renewable resources under the California RPS eligibility guidelines, and the eligibility of energy-for-export wind generation projects in México for Clean Development Mechanism (CDM) certification.
- Supported a major wind project developer in the evaluation of transmission options to wheel several hundred megawatts from Northern Baja California, México, to California utilities. Supported project developer in challenging the timeliness and results of the interconnection feasibility study performed by the transmission owner under the CAISO Large Generator Interconnection Process and represented the developer in the Generator Interconnection Process Reform (GIPR) stakeholder meetings. The GIPR led to the current FERC-endorsed project cluster analysis approach to managing the CAISO interconnection queue.
- Expert witness in the permitting of Texas/Northeast México's first high voltage direct current open access transmission interconnection (Sharyland Utilities/Hunt Power). The Public Utility Commission of Texas (PUCT) found no justification for investing ratepayer's funds in the construction of a 300-MW DC tie between Texas and México's transmission systems. Proponents raised the project to the consideration of an Administrative Law Judge to seek public funding approval. The Texas ALJ was persuaded by what he said was "particularly persuasive" testimony and recommended the PUCT approve the projects. The tie became operational during the summer of 2007.

Engineering, market, economic, and financial advisory

- Provides policy and economic analysis support to Jupiter Power, LLC., a utility scale battery storage facility developer, in assessing multi-regional market participation models.
- Represented the Mississippi Public Service Commission in the MISO Stakeholder Working Group developing the planning business practices related to utility scale battery storage as a transmission only asset (SATOA).
- Represents the MPSC in the Organization of MISO States Distributed Energy Resources Working Group.
- Developed zonal and nodal market price forecasting models of México's interconnected electric power grid using ABB's MarketPower and PROMOD IV simulation platforms for dispatch analysis and economic determination of long-term capacity additions. The models have been used in the independent market and economic analysis of several natural gas and renewable energy generating facilities, as well as in the economic analysis of US-México cross-border electricity trade.
- Conducted market and commercial due diligence in the acquisition of a large combined cycle facility under construction and advised investors on the risks in the existing long-term energy and capacity PPA with CFE. The long-term analysis of the plant's commercial viability required the development of a 30-year generation and transmission expansion plan for the regional transmission system in which the plant will operate, and an analysis of the long-term availability of natural gas to fuel the generating facility.

- Developed a comprehensive briefing on the laws, regulations and electric market rules for a Canadian generation project developer and operator considering entry into the Mexican electric market auctions. The briefing explored available business opportunities and associated risks for bilaterally contracted and merchant generation projects.
- Conducted a valuation of a run-of-river hydroelectric facility under development in México. The valuation considered the potential revenue from the sale of Clean Energy Certificates during the economic life of the project.
- For two Canadian pension funds, conducted market and regulatory due diligence on a portfolio of greenfield hydroelectric and wind generation projects in various stages of development, including the feasibility of transmission access and the risk of security and social unrest. Evaluated the economic viability of early development stage projects in the portfolio under restructured electric market conditions and the projects competitiveness in future renewable energy auctions.
- Led the market and regulatory due diligence for the acquisition of a series of run-of-the-river mini-hydro generating facilities with an aggregate capacity of 122 MW in Colombia. The due diligence review of the projects included the analyses of the legal and regulatory framework of the Colombian energy sector; its energy demand/supply balance; the planned expansion of its infrastructure; the structure and operation of its electricity market; and, the mechanics of electricity price formation. An econometric model was developed to forecast the spot market price of electricity over the life of the project.
- For Macquarie Capital (México) carried out electric power market price and regulatory risk analyses in support of the acquisition of the 396-MW Mareña Renovables wind farm project in Oaxaca, México. The project was acquired by the Macquarie Mexican Infrastructure Fund (MMIF), MacCap and FEMSA from Preneal, a Spanish wind farm developer.
- Retained by México's largest cinema chain to advise on the acquisition of renewable electricity supply for its cinemas. Developed an electric load model for the chain to accurately reflect the unique load patterns of the business and applied it to compare the cost of energy and capacity supply, from several candidate renewable energy suppliers, to that of the Mexican government utility. Assisted in evaluating the disparate terms and conditions of various competing supply offers on a comparable basis.
- Conducted a due diligence review of generation- and transmission-related risk for a wind electric generation project owned by multiple remote industrial off-takers. On behalf of the project's lenders, studied numerous issues related to a unique Mexican interconnection and energy value banking contract that enables intermittent renewable generators to firm-up supply to their off-takers.
- Conducted a historical and prospective analysis of marginal prices of electricity in the United States and México States of Texas, New Mexico, Arizona, Sonora and Chihuahua for a leading US independent transmission developer. Locational marginal prices (LMPs) in the US markets of interest were modeled using AURORAxmp, a multi-area, transmission-constrained chronological economic dispatch model developed by EPIS, Inc. Short-term load-weighted LMPs were modeled for loads and fuel prices forecasted using "frozen" transmission and generation topologies (no expansion).

- As transmission advisor to a major Spanish energy company, advised on the technical and economic aspects of a proposed 500-MW wind farm located in Northern Baja California, México. Advised the project developer in negotiations with potential project off-takers and transmission owners, and supported its applications for interconnection with the California ISO and for certification as an in-state renewable resource with the California Energy Commission (CEC). Facilitated communications between the Mexican and California energy policy and regulatory authorities and grid operators. Carried out a comparative analysis of environmental and other siting regulations applicable to wind power projects in the US and México.
- Carried out a due diligence review of transmission-related risk for a wind electric generation project owned by multiple remote industrial off-takers. On behalf of the project's lenders, studied numerous issues related to grid risk, including (1) the incidence of interruptions at the interconnection point due to system emergencies, (2) potential grid instability due to rapidly growing wind capacity interconnecting to the same area of the grid, (3) the incidence of service interruptions in the delivery points, (4) the condition and maintenance practices associated with local reception facilities, (5) uncertainty in utility interconnection requirements and cost, and (6) the future stability of the pricing provisions in the project's transmission contract.
- Carried out market, regulatory, and commercial due-diligence as independent market consultant to senior lenders in the financing of the 125-MW La Ventosa–Eléctrica del Valle de México wind farm in Oaxaca, México (SIIF/Credit Agricole Indosuez). One of the first large-scale wind farms in México, this project presented the lenders with various types of project risks never addressed before in México. Assessed the technical, market, and regulatory risks of the project and formulated potential mitigation measures. The effort resulted in the first-time recognition by the Mexican government of the need to reinforce the grid to accommodate the large wind power potential in the La Ventosa, Oaxaca region.
- Conducted market, regulatory, and tariff analyses for financing due diligence of a 500-MW gas-fired combined-cycle plant independently owned and operated in México. As one of the few IPP plants in México to sell power to CFE without a fuel price warranty from the government, the plant was subject to dispatch risk during periods of high natural gas prices and relatively low residual oil prices. Developed analysis of the impact of high natural gas prices on plant dispatch. This analysis contributed to the Mexican government's renegotiation of the plant's natural gas supply contract.
- Led an independent due diligence analysis of the Interim Financial Model supporting the non-recourse financing of a 112-MW wind electric project in Oaxaca, México. The purpose of the analysis was to assess the integrity of the model's performance in providing reported results for the financing plan as implicitly designated in the Model, and as generally described in the Preliminary Information Memorandum (PIM) for the Project. This was primarily a review of the model logic and calculations. The assessment looked at the model's performance with respect to the following factors:
    - Determination of total project costs and disbursement of equity and debt during the construction period.
    - Determination of expected revenue during operations.
    - Determination of expected costs during operations.
    - Determination of debt service per the described loan and hedging arrangements.
    - Determination of debt service coverage ratios.

- Determination of the debt service reserve account.
- Determination of resulting net earnings and return on equity for the sponsor.

With respect to the determination of project costs, revenues and operating costs, the model was checked for consistency with the project sponsors' Technical Consultant's draft report prepared by a wind technology firm.

- Developed a GIS-based project-siting methodology for utility-scale solar photovoltaic generation facilities. The methodology considers the location of transmission and sub-transmission infrastructure along with known siting constraints, including county land-use plans, utility and conservation easements, environmentally sensitive areas and critical habitats, state and national parks, and military bases. Parcel ownership GIS-data enables the project developer to expedite the acquisition of project land and right of way for project access and interconnection infrastructure.
- Developed a comprehensive market price forecasting model of México's interconnected electric power grid. Capable of analyzing system dispatch and pricing at the regional level, the model represents the Mexican power grid as a network of seven distinct "market areas." The model uses Ventyx's MarketPower® simulation platform for dispatch analysis and economic determination of long-term capacity additions. The model's inputs describe the regional demand forecasts; capacity additions/retirements; fuel price forecasts; and transmission capacity. Additional inputs for each generation plant in México, current and planned, describe key thermal, electric and economic characteristics (capacity, fuel, type of prime mover, heat rate, O&M, forced outage rates, maintenance, and availability). The model simulates generation dispatch given individual generator's projected cost of operations and inter-area transmission system limitations. The model has been used to support the financial analysis of several natural gas and wind power plants, as well as in the economic analysis of US-México cross-border electricity trade.
- For a leading solar photovoltaic manufacturer, developed a comprehensive geo-referenced primer on the electric power markets of California, Arizona, Nevada, and New Mexico. This extensive reference volume makes use of hyperlinked geo-referenced maps to provide optional depth understanding of the South Western US solar resources, electricity demand, generation and transmission infrastructure, and policies and regulations regarding renewable portfolio standards and interconnection to the electric power grid. This hyperlinked primer is used by upper level management in the firm.
- Coordinated collaboration between the CEC and Mexican Government energy agencies to implement border policy options defined in the CEC's 2005 Integrated Energy Policy Report. Utilized long-established working relationships with senior management and staff at Mexican energy agencies to address the practical economic and political implications of coordinating cross-border energy policymaking.
- Performed a market assessment of energy efficiency technologies and combined heat and power for industries in the California/Baja California, México cross-border region for the CEC. Designed an innovative market research framework using field surveys (and other resources) and GIS techniques to collect and deliver market data that enabled US technology and project development companies to better target potential customers. To improve survey response rates, arranged survey collaborations with key industrial chambers of the three major cities and the Baja California state government.

- Performed energy supply and demand assessment for the California/Baja California, México Border region in response to the CEC need for new statewide energy policies. Reported on the energy demand and supply situation in the region of Baja California, México. Compiled information on electric generation and transmission expansion plans, government demand-side management programs, and liquefied natural gas regasification supply plans.
- Developed a fuel-purchasing risk-management strategy, organizational structure, and IT systems design for the new risk-management department of México's CFE (fifth largest electric utility in the world). Participated in various capacities in developing an overall strategic plan for fuel risk management and in the design of the necessary organizational structure, business processes, and systems to establish a fuel procurement and risk management organization to address all risks associated with fuel markets, foreign exchange, and interest rates.
- In connection with a project sponsored by the World Bank, studied electric outage costs for the Secretaría de Energía y Minas. Formed a strategic alliance with a local firm and retained one of the world's foremost experts in outage costs. (Argentina's financial crisis precluded the completion of this work.)
- Designed an efficient lighting market transformation program for the Philippines (PELMATP) to be funded by the Global Environmental Facility (GEF) through the United Nations Development Programme. GEF granted $5.5 million to implement the program administered by the Philippine government.
- Designed a three-year $4.5 million USAID-funded commercial/industrial utility demand-side management program for the Philippines and personally managed the project from 1996 to 1998.
- For the US Trade and Development Administration, carried out a feasibility study of an industrial energy efficiency program for a private distribution utility in the Philippines.
- At ANCO Engineers, led one of the largest demand-side management practices in the United States and managed over 120 consultants delivering DSM programs outsourced by some of the largest US electric utilities, including PG&E, Wisconsin Electric Power Co., and Consolidated Edison of New York.
- Extended ANCO's well-established reputation in seismic and other sensing technology RD&D to energy end-use technologies, including field performance measurement of gas and electric energy efficient end-use technologies and the application of expert systems to military portable electric generation systems.
- Carried out an assessment of the internal market-readiness of GRI's products and services for international markets. To gain an up-to-date understanding of the international natural gas industry's needs for technology research, development and commercialization (RD&C), carried out in-depth written and oral surveys of over 100 executives of leading natural gas companies and R&D organizations, as well as gas industry experts and influencers in GRI's geographical areas of interest. Developed surveys to explore the specific views of executives of the RD&C, sales/marketing, and operations organizations of the participating companies and institutions, and to identify key business, marketing, and operations technology needs representing opportunities for GRI's Products/Service Lines. The information collected was assembled into a knowledge database

of best practices in RD&C, sales/marketing, and operations of natural gas transportation, distribution, and commercialization companies in Europe, Latin America, and Australasia.

- For the Southern California Gas Company, served as technical advisor for natural gas end-use market studies targeting commercial, industrial, and agricultural customers. Conducted the development of multi-battery customer mail surveys to measure appliance saturation and customer attitudes, needs, behavior, and satisfaction. Provided technical guidance for phone surveys designed to identify barriers to the delivery of energy efficient equipment to the marketplace. The surveys considered gas-fired furnaces, boilers, and air conditioning systems, as well as gas-fired industrial processes and building energy management systems.

Annex B: Work Products

BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

Application of PSEG Renewable Transmission LLC for a Certificate of Public Convenience and Necessity to Construct a New 500 kV Transmission Line in Portions of Baltimore, Carroll and Frederick Counties, Maryland.	* * * * * * *	Case No. _____

PSEG Renewable Transmission LLC

Maryland Piedmont Reliability Project

Direct Testimony of
Collin Cain, M.Sc.

Topics Addressed: Economic Impact Analysis

Date: December 31, 2024

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Collin Cain. I am a Partner with Bates White Economic Consulting ("Bates White"). My business address is 2001 K Street N.W., North Building, Suite 500, Washington, D.C. 20006.

Q2. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL EXPERIENCE.

A2. I have a B.A. in Economics and Political Science from the University of Toronto and an M.Sc. in Economics from the London School of Economics. I have more than 20 years of experience in power sector economic analysis, cost benefit analysis, asset valuation, and wholesale power markets design. Prior to joining Bates White, I was a consultant in the energy practice of NERA economic consulting in New York and Washington, D.C.

Q3. PLEASE DESCRIBE BATES WHITE.

A3. Bates White is an economic consulting firm with over 180 degreed professionals in economics, finance, and engineering. In addition to its Energy Practice, Bates White has practice areas in Antitrust, Finance, Intellectual Property, Healthcare, Mass Torts, and Transfer Pricing and Tax. The firm is located in Washington, D.C.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION (THE "COMMISSION')?

A4. Yes. I previously submitted written testimony and appeared at an evidentiary hearing in Commission Case No. 9666, on behalf of Skipjack Offshore Energy, LLC.

Q5. HAVE BATES WHITE PERSONNEL WORKED ON BEHALF OF THE COMMISSION AND TESTIFIED IN OTHER PROCEEDINGS BEFORE THE COMMISSION?

A5. Yes, Bates White personnel have served the Commission in several roles, most notably as the Staff's Technical Consultant for the Commission's Standard Offer Service ("SOS") RFPs from 2004-06 and from 2009 to the present.

Q6. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A6. I am testifying on behalf of PSEG Renewable Transmission LLC ("PSEG Renewable Transmission" or the "Company") in support of its Application to the Commission for a Certificate of Public Convenience and Necessity ("CPCN") in order to construct the Maryland Piedmont Reliability Project ("MPRP" or the "Project").

Q7. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A7. The purpose of my testimony is to summarize the analysis of economic impacts expected within the state of Maryland from development and construction of the MPRP. Bates White performed the analysis, presented in the report, "Maryland State Economic Impact Analysis for the Maryland Piedmont Reliability Project." A copy of the same is attached to PSEG Renewable Transmission's CPCN Application as Attachment C.

Q8. BRIEFLY DESCRIBE THE MPRP.

A8. As detailed in the Application and in the direct written testimonies of other PSEG witnesses, including Jason Kalwa and Dawn Shilkoski, the MPRP is a greenfield 500 kilovolt ("kV") AC overhead transmission line that will extend from the Conastone

Demarcation Point with the Otter Creek Line to Doubs Station. The MPRP goes through portions of Baltimore County, Carroll County, and Frederick County, in northcentral Maryland. PJM Interconnection, LLC ("PJM"), which serves as the Regional Transmission Organization ("RTO"), has directed the Company to construct, own, operate and maintain the MPRP as necessary to ensure the continued reliability of the electric transmission system serving Maryland and the surrounding Region. PJM requires the MPRP to be in service by June 1, 2027.

Q9. PLEASE DESCRIBE THE ECONOMIC IMPACT ANALYSIS PERFORMED BY BATES WHITE.

A9. Bates White quantified the positive economic impacts to Maryland from development and construction of the MPRP by applying the Joint Economic Development Impact ("JEDI") model, developed by the U.S. National Research Energy Laboratory. JEDI is an economic input-output model that uses evaluated linkages among different sectors of the economy to estimate how dollars spent on certain activities affect economic activity and job creation across the economy. Bates White applied inputs for expected in-state expenditures provided by PSEG Renewable Transmission, including capital expenditures local to Maryland of approximately **$230 million**, and annual in-state spending for ongoing operations and maintenance estimated at **$1.2 million per year.**

Q10. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSIS.

A10. The results of the economic impact analysis show that construction and operation of MPRP's in-state Maryland facilities will provide economic benefits to the Maryland economy summarized below (in 2023 dollars). Impacts from operations are presented conservatively as a sum over 30 years, though the economic life of the assets is likely to be more than 40 years.

- Increased economic value added, effectively the net economic impact, of **$306 million:**
  - $251 million, during development and construction
  - $55 million, over the first 30 years of operation
- Increased earnings within the state of **$230.0 million:**
  - $199 million, during construction
  - $40 million, over the first 30 years of operation
- Increased employment:
  - **1,709** full-time equivalent (FTE) employment over the construction period
  - **11.0** annual FTE impacts from operations expenditures
- Increase in total economic output of **$416 million:**
  - $342 million, during construction
  - $74 million, over the first 30 years of operation
- Increase in state sales tax revenue from construction expenditures of approximately **$9.4 million**.
- Increase in state and local property tax revenue of approximately **$1.4 million** annually.

Q11. ARE THERE ADDITIONAL ECONOMIC BENEFITS FROM THE PROJECT THAT ARE NOT QUANTIFIED IN THE ECONOMIC IMPACT ANALYSIS?

A11. Yes. The economic impact analysis does not quantify the value of improved electric system reliability that justifies the Project. PJM selected the MPRP (and other transmission projects) for inclusion in the Regional Transmission Expansion Plan ("RTEP") through the 2022 Open Window 3 process ("Window 3"). PJM selected the MPRP (and other selected Window 3 projects) as Reliability Projects and not as Market Efficiency Projects. This means that the MPRP and the other PJM-selected projects address and resolve serious reliability violations that are forecasted to occur on the regional transmission system if no action is taken.

By reducing the probability of system outages resulting in loss of service to customers, the MPRP (and the Window 3 portfolio) will provide significant value associated with the value of lost load ("VOLL"), which measures the cost to electricity customers (residential, commercial, and industrial) of the involuntary loss of power. Because the cost of significant outages is so high, reducing the likelihood of such events will provide substantial value to Maryland over time relative to the recovery of project costs through customer rates.

The economic value of these additional benefits is not included in the economic impact analysis presented in the Bates White report, as quantifying the benefits formally entails power system and market modeling outside the scope of our work. The expected economic benefits to Maryland are nonetheless very real and may be on the order of tens of millions of dollars annually for Maryland customers, as discussed in the Bates White report.

Q12. WHAT ADDITIONAL INFORMATION IS INCLUDED IN THE BATES WHITE REPORT?

A12. The report includes additional detail on the study results for estimated impacts from the MPRP in the standard categories of direct, indirect, and induced impacts on state employment, earnings, economic output, and value added. The report also provides additional discussion of these impact categories as well as the additional non-quantified benefits of improved electric system reliability.

Q13. DOES THIS CONCLUDE YOUR TESTIMONY?

A13. Yes, although I reserve the right to supplement this testimony as appropriate.

Maryland State
Economic Impact Analysis for the
Maryland Piedmont Reliability Project

Prepared by

Bates White Economic Consulting

December 20, 2024

Table of contents

List of Figures

List of Tables

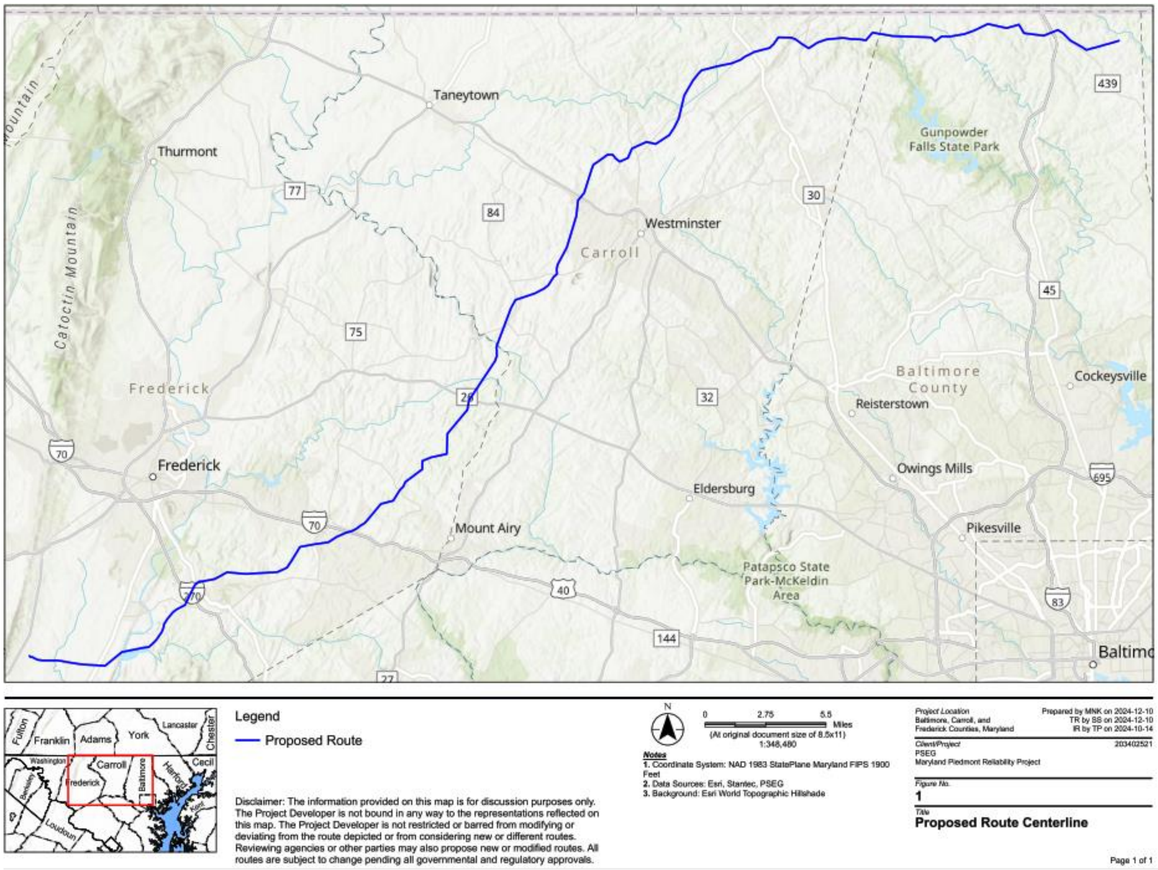
I. Executive Summary[1]

The Maryland Piedmont Reliability Project ("MPRP") is a greenfield 500kV AC overhead transmission line that will extend from a connection point within the BG&E transmission line right-of-way in Baltimore County to the Doubs 500kV Station in Frederick County. Totaling approximately 70 miles in Baltimore, Carroll, and Frederick Counties in Maryland, the MPRP transmission line is a reliability solution proposed by, and awarded to, PSEG Renewable Transmission LLC ("PSEG") within the 2022 "Window 3" solicitation as part of the PJM Interconnection, LLC ("PJM") annual Regional Transmission Expansion Plan ("RTEP"). PJM is the regional transmission organization ("RTO") that plans and operates the regional transmission system and administers the wholesale energy and capacity markets in Maryland and all or parts of 12 other states in the Mid-Atlantic region, including the District of Columbia. The MPRP is expected to enter commercial service in June 2027.

Figure 1 shows the planned route for the MPRP based on the routing analysis performed by the Company's environmental and routing experts, Stantec.

[1] Bates White Economic Consulting (Bates White) was engaged by PSEG, the developer of the Project, to perform an analysis of economic and employment impacts in the State of Maryland expected from construction of the MPRP transmission facilities.

Figure 1: MPRP Planned Routing[2]



Construction and operation of the MPRP bulk transmission facilities will entail substantial activity and expenditures in Maryland. PSEG's capital expenditures local to Maryland are estimated at approximately **$230 million**, and annual in-state spending for ongoing operations and maintenance are estimated at **$1.2 million** per year.[3] These in-state expenditures will stimulate further economic activity and employment in Maryland, as described in the analysis presented below.

Total positive economic impacts from the MPRP local expenditures will be substantial. Bates White quantified the positive economic impacts to Maryland from development and construction of the MPRP by applying the Joint Economic Development Impact ("JEDI") model, developed by the U.S. National Research Energy Laboratory. JEDI is an economic input-output model that uses evaluated

[2] Provided by PSEG.

[3] Unless otherwise noted, dollar values in this report are expressed in 2023 dollars.

linkages among different sectors of the economy to estimate how dollars spent on certain activities affect economic activity and job creation across the economy. As set forth further below, there are additional positive economic benefits from the MPRP that will accrue within Maryland stemming from the facilities' effects on the PJM system and markets, which Bates White has identified but has not attempted to quantify.

The results of the economic impact analysis show that construction and operation alone of MPRP's in-state Maryland facilities will provide economic benefits to the Maryland economy summarized below (in 2023 dollars). Impacts from operations are presented conservatively as a sum over 30 years, though the economic life of the assets is likely to be more than 40 years.

- Increased economic value added, effectively the *net* economic impact, of **$306 million:**
    - $251 million, during development and construction
    - $55 million, over the first 30 years of operation
- Increased earnings within the state of **$239 million:**
    - $199 million, during construction
    - $40 million, over the first 30 years of operation
- Increased employment:
    - **1,709** full-time equivalent (FTE) employment over the construction period
    - **11.0** annual FTE impacts from operations expenditures
- Increased total economic output of **$416 million:**
    - $342 million, during construction
    - $74 million, over the first 30 years of operation
- Increased state sales tax revenue from construction expenditures of approximately **$9.4 million**.
- Increased state and local property tax revenue of approximately **$1.4 million** annually.

These total economic impacts from the MPRP construction and operation expenditures reflect the sum of effects that are characterized as "direct," "indirect" and "induced." Direct effects derive from the immediate local expenditures on goods and services. Indirect effects include those on industries supplying goods and services supporting the direct activities. Induced effects are those caused by increased income and consumer expenditures in the economy.

Additional Value from Improved Reliability

PJM has selected the MPRP and the other Window 3 facilities to be constructed as Reliability Projects and not as Market Efficiency Projects. Essentially, this means that the MPRP and the other Window 3 projects address and resolve serious reliability violations that are forecasted to occur on the regional transmission system if no action is taken. PJM has determined that reliable operation of the system necessitates construction of the Window 3 projects and has not quantified the economic value provided by the facilities, though the benefits to the region, and to Maryland specifically, of improved reliability will be substantial.

By reducing the probability of system outages resulting in loss of service to customers, MPRP and the Window 3 portfolio will provide significant value associated with the value of lost load (“VOLL”), which measures the cost to electricity customers (residential, commercial, and industrial) of the involuntary loss of power. A rough calculation presented in Section III.3.1 illustrates the value of reliability improvements, which may be on the order of tens of millions of dollars annually for Maryland customers. Because the cost of significant outages is so high, reducing the likelihood of such events will provide substantial value to Maryland over time relative to the recovery of project costs through customer rates.

The economic value of these additional benefits is not included in the economic impact analysis presented in this report, as quantifying the benefits formally entails power system and market modeling outside the scope of our work. The expected economic benefits to Maryland are nonetheless very real, and likely to be substantial, as discussed in detail below.

II. Project Background

PSEG proposed the MPRP to PJM as a solution to numerous forecasted system reliability violations identified in PJM's 2022 Regional Transmission Expansion Plan ("RTEP") Window 3 solicitation.[4] As part of the competitive bid process, PJM received 72 separate proposals from 10 utilities and transmission developers,[5] and ultimately determined that a combination of existing transmission upgrades and greenfield buildouts (including MPRP) was the best fit to meet significant reliability needs identified in the 2022 RTEP.[6] The MPRP is a greenfield 500kV high-voltage AC overhead transmission line that will extend from a connection point within the BG&E transmission line right-of-way in Baltimore County to the Doubs 500kV Station in Frederick County. The MPRP is approximately 70 miles in length and will traverse a route across portions of Baltimore, Carroll, and Frederick Counties in Maryland. PJM requires that the MPRP be in service by June 2027.

II.1. Project Justification

PJM is requiring that PSEG construct the MPRP in order to ensure the continued safe and reliable operation of the regional transmission system, accommodating growing regional energy needs. PJM has determined that the MPRP is necessary for two main reasons: to maintain system reliability amid a higher demand for electricity in the region and to direct more generation capacity to the area to mitigate the impact of fossil-fuel generator retirements.[7] Since PJM developed its 2022 RTEP base case, 11,100 MW of generation deactivations have been announced and approximately 5,300 MW of generation retirements have occurred since the original 2022 RTEP case was created.[8]

[4] PJM, "PJM's Role in Regional Planning/2022 RTEP Window 3," PJM, July 8, 2024, 3-4; https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjms-role-in-regional-planning-2022-rtep-window-3.ashx.

[5] PJM, "Reliability Analysis Update"; https://www2.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-item-15---reliability-analysis-update-2022-window-3.ashx.

[6] *Id.*, 14.

[7] PJM, "Reliability Analysis Update," 2.

[8] *Id.*, 2.

III. Maryland Economic and Employment Impacts

The economic and employment impacts from construction and annual O&M of the MPRP were calculated using the NREL's JEDI model, Transmission Module. JEDI is an input-output model that applies data on the linkages among different sectors of the economy to estimate how dollars spent on certain activities affect economic activity and job creation across the economy. JEDI is an established tool for evaluating economic impacts expected from development of new transmission projects.

Assessing economic impacts requires specification of the location of focus, and consideration of only those expenditures that will affect that location. As discussed above, development and operation of MPRP will require substantial activity and expenditures in Maryland. Maryland will benefit from positive economic impacts during the development and construction phases of the work, and from ongoing expenditures associated with annual O&M required over the life of the facilities. While activity during development and construction is expected to generate significant economic activity and jobs in the near term, the benefits to Maryland are inherently long-term, as the new facilities that constitute the Project will serve the area well into the future.

Bates White has not quantified significant potential positive economic benefits, such as avoided outage costs, lower energy costs resulting from reduced transmission congestion, and lower capacity prices resulting from increased deliverability of capacity into Maryland. Neither has Bates White quantified potential adverse impacts associated with property value (i.e., property other than right of way for which landowners are directly compensated), potential impact on agricultural value of farms/temporary interference with farming operations, or impacts on viewshed, etc.

III.1. MPRP Estimated Local CapEx and Employment

PSEG anticipates MPRP capital expenditures local to Maryland of approximately **$230 million**.[9] This amount includes activities related to:

[9] Total project cost is estimated at approximately $390 million, with approximately 40% of spending – largely for steel structures and overhead wires – occurring outside the state of Maryland.

- Development and preconstruction activities, such as land acquisition, engineering and surveying services, and environmental and permitting services;
- Materials and equipment;
- Labor and installation, for civil construction (e.g., grading, roads, site prep, foundations, fencing) and heavy construction (e.g., tower erection and conductor stringing)

In addition to construction-related expenditures, there will be significant annual operations and maintenance (O&M) expenditures that will continue through the expected 30+ years of MPRP operations.

III.2. Economic Impact Analysis

III.2.1. JEDI Input-Output Model

The JEDI model estimates impacts on employment, earnings, and economic output from development and construction of transmission facilities. As with other input-output models, JEDI's analysis of impacts is based on the application of economic multipliers, which represent the amount by which one economic variable, such as employment by sector, changes in response to an economic action, such as increased construction expenditure. Economic multipliers contained within the JEDI model are derived from Minnesota IMPLAN Group's IMPLAN regional input-output software and state data files. The IMPLAN database contains county, state, zip code, and federal economic statistics which allow estimation of impacts at the state level.

The analysis presents the impacts for three categories of economic effect:

- *Direct* – Impacts caused by the initial change in spending or demand.
- *Indirect* – Impacts in the industries supplying goods and services supporting the direct activity.
- *Induced* – These changes are due to the increased incomes from increased employment. Induced effects represent the additional purchases of consumption goods and services by additional income stemming from the direct and indirect impacts.

Results are presented below for four economic variables:

- *Jobs* – Additional employment from the increased final spending are classified as direct, indirect, induced and total.

- *Earnings* – The additional earnings associated with the additional employment.
- *Output* – The additional output that drives the increase in employment.
- *Value added* – The sum total of earnings of capital and labor. The sum total of value added of all enterprises and self-employed in a state comprises that state's GDP.

III.2.2. Maryland Economic Impacts

The estimated economic value-added impacts of MPRP for Maryland are summarized in Table 1 below. The reported figures represent the value added to the Maryland economy from direct, indirect and induced effects of local capital expenditures.

Table 1: Maryland Economic Value Added Impact (2023$ millions)

Impact Category	Local Value Added		
	CapEx/DevEx	O&M (30 yrs)	Total
Direct	$166	$27	**$193**
Indirect	$40	$8	**$47**
Induced	$45	$20	**$65**
Totals	**$251**	**$55**	**$306**

Construction of MPRP, and operations over 30 years, would contribute approximately **$306 million** (in 2023 dollars) of value added to the Maryland economy.

III.2.2.1. Context for Value Added Impact Measure

Table 1 presents the economic "value added" impact to the Maryland economy. Value added is effectively a net impact value, smaller than "economic output," and more appropriate to measuring economic effects relevant to Maryland residents.

The difference between "value added" and economic output can be illustrated using a simplified example. A car dealer pays $28,000 to a manufacturer for a car that the dealer sells to a consumer for $30,000. The $2,000 of dealer markup covers $1,000 of business costs and $1,000 of wages and capital income. The latter $1,000 corresponds to the value added of the vehicle dealer. If the car was produced in Maryland, at a manufacturer cost of $20,000, then the remaining $8,000 of the $28,000 price to the dealer would be the *manufacturer's* value added. Total value added in this example would be $9,000 ($1,000 to the dealer and $8,000 to the manufacturer), while economic output would correspond to the $30,000 retail sale price. The difference reflects the fact that value added nets out the economic activity necessary to get a final product ready for sale and thus avoids double-counting. Consequently, for any impact analysis, economic output will generally be significantly greater than value added, with the latter measure being the one most relevant to the local economy.

III.2.3. Maryland Earnings

JEDI estimates an increase in earnings of **$239 million** in Maryland - $199 million from construction and $40 million over 30 years of operation. As noted, the analysis does not include the effect of property taxes expected to be paid by MPRP. The JEDI impact analysis also does not account for effects from increased income and other taxes paid as a result of earnings. Such effects are excluded from the value added figures in Table 1 above. The value added and net benefits from the Project would be greater if these effects were included.

III.2.4. Maryland Employment Impacts

JEDI outputs include the additional employment stimulated in the economy by the Project. As with the economic value-added results summarized above, these employment impacts are categorized as direct, indirect and induced. Direct employment is determined by the direct local spending on project materials and services. The direct employment estimate implicitly reflects labor under direct project management and also reflect direct employment linked to other expenditures, such as those for locally-source materials.

The indirect category captures job impacts in supporting industries that are associated with, but a step removed, from those providing direct goods and services. Finally, the induced category captures job impacts induced in the economy more broadly by the activity during construction. The JEDI model output only reflects employment created in the State of Maryland as a consequence of local expenditures. The employment impact results from the JEDI model are shown in Table 2.

Table 2: Maryland Employment Impacts from Construction

Economic Impact Category	Full-time Equivalent years (FTE-yrs)	Annual Jobs Assuming 3-year Development and Construction
Direct impact	802	267
Indirect impact	430	143
Induced impact	478	159
Totals	**1,709**	**570**

JEDI estimates employment impacts based on the categorization of aggregate expenditures, and produces values in years of full-time equivalent (FTE) employment, shown in the middle column of Table 2. The rightmost column of the table puts these employment values in terms of annual jobs, based on the assumption that project activity will span approximately three years, with construction itself expected to take approximately 18 months.

MPRP will also provide ongoing economic benefits from operation of the facility over its anticipated economic life. As described above, the impact from operations was conservatively evaluated over 30 years, though the facilities are likely to have a longer economic life. Table 3 summarizes the estimated state employment impacts from annual O&M expenditures.

Table 3: Maryland Annual Employment Impacts from MPRP Operation

Impact Category	Annual FTE Impacts
Direct	2.4
Indirect	2.1
Induced	6.4
Total	**11.0**[10]

As with the estimated employment impacts from MPRP construction, the values presented in Table 3 represent an expansive estimate from JEDI of employment impacts based on a translation of project expenditures by category into expected employment in the economy. More than half of the *induced* employment impact of 6.4 FTEs from annual operation expenditures is associated with annual property taxes.

[10] Values shown in the table reflect rounding of additional digits not presented.

III.2.5. Other In-State Business Impacts

As noted above, overall economic activity attributable to the Project is captured by the "economic output" resulting from the Project, capturing the total value of all transactions in the supply chain.

Table 4 summarizes the impact of construction and operation of MPRP on Maryland local economic output.

Table 4: Maryland Economic Output (millions $2023)

Impact Category	Local Economic Output Impact (2020$ millions)		
	CapEx	O&M	Total
Direct	$203	$30	**$232**
Indirect	$66	$12	**$78**
Induced	$73	$32	**$106**
Totals	**$342**	**$74**	**$416**

The direct economic output impact of **$203 million** for construction CapEx corresponds approximately to the estimated local spend of $230 million for MPRP. When indirect and induced impacts are considered, the Project is expected to generate a total of **$342 million** of economic activity in the State of Maryland during the construction phase. The total economic output impact of the Project, inclusive of impacts during operations, is approximately **$416 million**.

III.2.6. Impacts on State and County Tax Revenue

Over the construction period, the Project is expected to generate approximately **$9.4 million** in sales tax revenue for Maryland, based on estimated in-state expenditures on materials and equipment. Over 30+ years of operation, the project will also provide increased state and county property tax revenue, on the order of **$1.4 million** per year. Actual property taxes will depend on state and county assessments, and so are somewhat uncertain. The estimate of $1.4 million per year reflects estimated materials and easement values by county, and the corresponding county and state property tax rates for 2024/25.[11]

[11] https://dat.maryland.gov/Documents/statistics/TaxRates_2024.pdf.

III.3. System Reliability Benefits

Construction of MPRP in Maryland will have other benefits that are not captured in the economic impact analysis presented above. Principal among these will be sustained system reliability compared to the status quo of the transmission system. MPRP and the other Window 3 projects are needed to address numerous forecasted reliability criteria violations caused by a combination of significant load growth and generation retirement in the region. In combination with other elements of the Window 3 portfolio, MPRP is also expected to increase the deliverability of available power supply into Maryland, which will help address generation capacity needs arising from the retirement of older fossil-fuel generations in the state.

III.3.1. Value of System Reliability Benefits

MPRP is a Reliability Project rather than a Market Efficiency Project, which means that it addresses and resolves forecasted reliability violations rather than simply providing economic relief of system congestion.[12] Under PJM transmission planning procedures, Market Efficiency Projects must be justified by demonstrating economic benefits to load that exceed project costs over time. Because Reliability Projects such as MPRP are deemed necessary to maintain and ensure future compliance with NERC reliability criteria, PJM does not perform an explicit analysis that would quantify a dollar value of such benefits from the facilities. There is no question, however, that MPRP will provide substantial economic value to the region, and to Maryland specifically, by improving the reliability of the region's transmission system, which reduces the potential for electric service interruptions.

The value of reliability is often considered relative to a metric called the value of lost load (VOLL), which measures the cost to electricity customers (residential, commercial and industrial) of the involuntary loss of power. VOLL represents the cost to customers of an outage and, by extension, the presumed maximum price customers would be willing to pay to avoid interruption. The value of system reliability improvements can be calculated as VOLL multiplied by the reduction in probability of an outage. This is a complicated and challenging calculation, as it involves simulation of uncertain extreme system conditions years into the future. As noted, the estimation of economic

[12] Most transmission systems in the U.S. are planned to maintain reliability such that involuntary customer loss of load occurs no more often than 1 day in 10 years. Transmission congestion occurs when energy flows that would otherwise be economically useful are restricted by transfer limits on transmission facilities. While excessive transmission congestion may be associated with degraded reliability, maintaining the 1-day-in-10-years standard does not require elimination of all transmission congestion.

value is not performed for Reliability Projects, which are deemed necessary to maintain and ensure compliance with NERC reliability criteria. However, a rough calculation illustrates the value of reliability improvements, as follows.

VOLL is dependent on a variety of factors, including the duration of outage, customer class, time of year, and weather conditions. An outage of an hour may impose a modest cost on residential customers but could have much larger impacts on an industrial customer in the middle of a critical manufacturing process. Longer outages can impose direct costs on residential and commercial customers associated with food spoilage for example, but in extreme weather conditions, hot or cold, can impose large costs and/or threaten health and safety. Since many factors involved, it is challenging to assign a single dollar value to the loss of electric service, and estimates can range from the low thousands of dollars per megawatt-hour (MWh) to tens of thousands of dollars per MWh. As an illustration of the value of reliability (or the cost of a lack of reliability), consider an outage of 10 hours across the state of Maryland. Average hourly sales of electricity in Maryland in 2023 were approximately 6,500 MWh.[13] At a VOLL of $10,000/MWh (a somewhat conservative estimate), the cost of a 10-hour outage to Maryland customers would be approximately $650 million (=10hrs x $6,500 MWh x $10,000/MWh). Correspondingly, this is the value of *avoiding* one such event in ten years by improving or maintaining system reliability.

PJM does not provide data such as changes in the distribution of outage probabilities over time that would allow estimation of the economic value of MPRP or the Window 3 portfolio as a whole. Nonetheless, the illustrative calculation demonstrates that reliability improvements have very large implicit value because of the large costs imposed by significant outage events.

[13] U.S. Energy Information Administration, Monthly Form EIA-861M, https://www.eia.gov/electricity/data/eia861m/xls/sales_revenue.xlsx

Needs Analysis of the Proposed 502 Junction-Mt. Storm-Meadowbrook-Loudoun 500 kV Transmission Line

Report to the Virginia State Corporation Commission

Prepared by Bates White, LLC

Case No. Pue-2007-00031
(Virginia Electric and Power Company and Trans-Allegheny Interstate Line Company)

Case No. Pue-2007-00033
(Trans-Allegheny Interstate Line Company)

January 4, 2008

Table of contents

List of exhibits

I. Executive summary

(1) The PJM mid-Atlantic region and the northern Virginia area rely on significant west-to-east power imports to serve their current load requirements. For example, the northern Virginia area had an actual summer peak load of 6,368 MW in 2006, and its demand is expected to grow to 6,833 MW in 2011. At the same time, northern Virginia has approximately 3,000 MW of local generation. Thus, in order to reliably serve its forecasted load in 2011, this area is expected to rely on about 4,000 MW of power imports from remote generators. In the absence of significant generation additions and/or load reduction, additional transmission infrastructure is critical to ensure that the backbone transmission system can reliably serve the expected load growth in the PJM mid-Atlantic region and the northern Virginia area. It should be noted that northern Virginia's projected 465 MW load growth is relatively small in comparison to the expected total load growth of PJM's mid-Atlantic region. Accordingly, its contribution to the need for regional system expansion might be viewed as relatively small; however, this does not alter the fact that the provision of reliable service to northern Virginia is critically dependent on the adequacy of certain regional transmission facilities that transport power not only to northern Virginia, but to much of the PJM mid-Atlantic region as well.

(2) On April 19, 2007, the Trans-Allegheny Interstate Line Company (TrAILCo) and Virginia Electric and Power Company d/b/a Dominion Virginia Power (DVP), filed separate applications with the Virginia State Corporation Commission (Commission) for the approval and certification of 500 kV transmission facilities. The facilities are the continuation of a proposed 500 kV transmission line that would originate in Pennsylvania, continue through West Virginia, and terminate in Virginia. The entire proposed line is known as the 502 Junction-Mt Storm-Meadowbrook-Loudoun 500 kV transmission line (Loudoun Line). The Virginia portion of this line would run for 28.1 miles from the West Virginia-Virginia border in Frederick County to a point at DVP's Transmission Line #580 in Warren County, near the Meadowbrook substation. From there the proposed line extends for approximately 65 miles across Warren, Fauquier, Rappahannock, Culpeper, and Prince William counties to terminate at DVP's existing Loudoun Substation in Loudoun County. According to the applications, the proposed transmission line is needed to serve growing demand in the mid-Atlantic and northern Virginia areas, while adhering to North American Electric Reliability Corporation (NERC) transmission planning criteria. The PJM study supporting the applications identifies 11 potential electric reliability problem events that could occur beginning in 2011 and one electric reliability problem that could occur beginning in 2014 if the proposed line is not built. Reliability studies using the DVP planning criteria also

indicate a number of NERC reliability violations that would impair DVP's ability to reliably meet expected demand in 2011 unless the proposed Loudoun Line is built by 2011. In other words, the need for the proposed Loudoun Line was assessed using both PJM planning criteria (i.e., from a regional perspective) and DVP planning criteria (i.e., from a local perspective).

(3) Bates White, LLC, was retained by the Staff of the Commission to conduct a review and independent verification of the Applicants' load flow modeling, contingency analyses, and reliability needs assessment as introduced in the applications to justify the new line. This report presents the results of the review of the modeling assumptions and inputs used by the applicants in their power flows and contingency analyses, and it provides an independent assessment of need for the proposed facilities. As described in the body of this report, Bates White assessed the reasonableness and consistency of the modeling assumptions and data inputs in the DVP, TrAILCo, and PJM power flow cases, in terms of generation, load, and transmission. Bates White found that these elements were reasonably consistent with the information known to the Applicants at the time of the analyses.

(4) In assessing the need for significant additional transmission infrastructure as required in this current proceeding, it is important to recognize the significant changes in federal and state energy policy that have transpired in recent years.

(5) To comply with Virginia statutory requirements that Virginia's electric utilities join a regional transmission organization, Dominion Virginia Power and Allegheny Power are now members of PJM. Among other things, PJM performs a transmission planning function with the objectives of ensuring the operation, maintenance, and timely expansion/enhancement of a reliable regional transmission system that fully complies with NERC reliability standards. It is also generally understood that PJM, consistent with espoused policy of the Federal Energy Regulatory Commission (FERC), views a geographically expansive, robust regional transmission system as a critical factor in the development, growth, and success of competitive wholesale power markets.

(6) This regional focus and scope of transmission system planning and operations, influenced by considerations of developing competitive wholesale power markets, is significantly different from the traditional system planning approach of electric utilities in at least two ways. Historically, utilities, largely if not exclusively, planned their transmission systems to meet the needs of their native load customers; and in doing so, utilities typically undertook an integrated resource planning approach in evaluating the economic and reliability trade-offs of potential transmission and generation alternatives. Barring significant change in federal and/or state law and policy, that

planning era, at least with respect to regional high-voltage transmission infrastructure, is largely in the past.

(7) From a rational policy perspective, given current Virginia law, the analysis and evaluation of proposed transmission infrastructure must recognize an expectation, and most likely a legal requirement, that Virginia's PJM member electric utilities productively participate in establishing and supporting the regional objectives of PJM in accordance with policy decisions of FERC. This does not diminish the importance of considering the infrastructure needs and impacts directly related to Virginia's citizens; however, as with the proposed transmission line in this proceeding, the consideration of proposed transmission infrastructure within Virginia may substantially involve regional loads and/or facilities remote to the Commonwealth.

(8) Planning studies used in the development of PJM's 2006 Regional Transmission Expansion Plan (2006 RTEP) indicate certain major backbone transmission lines are expected to overload as early as 2011, if certain contingency conditions occur. In other words, given expected demand growth, the current transmission system would not meet NERC reliability standards and would subject customers in the PJM mid-Atlantic region and northern Virginia to an unacceptable level of reliability risk by 2011. Further, this situation is expected to deteriorate in future years as electricity demand grows. Indeed, the revised 2007 PJM load forecast that projects higher expected load for both the DVP and Allegheny transmission zones makes the need for the proposed Loudoun Line even more critical than the results shown in the 2006 RTEP. To address and resolve this 2011 reliability issue, PJM selected the 500 kV 502 Junction-Mt. Storm-Meadowbrook-Loudoun transmission line project, jointly developed and proposed by Dominion Virginia Power and the Trans-Allegheny Interstate Line Company.

(9) In assessing the need for the proposed transmission line, it should be recognized that there are new market mechanisms in PJM that are designed to encourage new generation capacity and demand response and that these mechanisms could affect transmission facility power flows and (potentially) the need for new facilities. However, one cannot rely on market mechanisms for reliability planning. It may well be that the new markets will provide sufficient new generation and demand response to reliably meet the need over time. However, the mid-Atlantic region and the northern Virginia area face reliability issues in the near term that must be addressed with a high level of certainty. It would be highly risky to rely on market forces to resolve reliability issues.

I.1. Independent determination of need

(10) To independently evaluate the need for the proposed line, Bates White conducted contingency analyses according to industry reliability standards. Specifically, Bates White used DVP's planning criteria, which reflect NERC Reliability Standards. The results of the Bates White study indicate that without the proposed Loudoun Line, NERC and DVP reliability criteria cannot be met in either 2011 or 2016. In other words, there is a need to improve the existing power system to reliably serve the expected demand growth in both 2011 and 2016. The Applicants' proposed Loudoun Line would fully resolve the expected reliability violations in 2011. It is also important to note that the proposed Loudoun Line does not fully resolve the reliability violations in 2016. However, these residual reliability violations, expected to occur in 2016, will likely be addressed as the PJM RTEP process incorporates additional transmission upgrades required to meet the broader needs of the PJM system.

(11) Bates White's analyses and conclusions are based on data consistent with the PJM RTEP Base Case and the 2007 PJM Load Forecast used by the Applicants in their need analyses. However, since the time of Applicants' analyses, significant changes have taken place with respect to expectations of load growth, the establishment of generation and demand-side capacity markets and planned generation additions/retirements, and transmission upgrades. Any and/or all of these developments may affect the need for the proposed line.[1] Accordingly, Bates White is continuing to analyze the need for the line based on the latest available information and intends to introduce supplemental findings into this proceeding at the earliest possible time.

I.2. Alternatives

(12) Bates White studied several alternatives that could resolve the major contingency overloads expected to occur as early as 2011. The results of the transmission, generation, and demand response alternatives considered are described in Chapter 5 of this report.

(13) The two alternatives that Bates White considers *feasible* are:

A. Building a 502 Junction–Mt. Storm–Meadowbrook–Doubs 500 kV line ("Doubs Option") or

B. Replacing the 500 kV Meadowbrook–Loudoun segment of the proposed line with a 230 kV double-circuit line, in concert with the assumption that three Sempra units with a total

[1] For example, on December 21, 2007, as a response to the Staff's seventh set of data requests, Applicants provided updated power flow cases that contain, among other things, 118 units of additional generation not included in the Applicants' original power flow cases that were used in the April 19, 2007, applications.

capacity of 640 MW near Doubs will be on-line by 2011 ("Two 230 kV plus Sempra Option")

(14) Alternatives that Bates White examined but considers *more uncertain are*:

C. Building the Amos–Kemptown 765 kV line ("A-K Option"); however, the earliest in-service date of AEP's A-K line is 2012, and, thus it cannot resolve the expected 2011 reliability violations

D. Installing AC power flow controllers in concert with the assumption that additional generation will come on-line in strategic locations

(15) Alternatives that Bates White finds *not feasible* are:

A. Terminating the proposed line at the Meadowbrook substation ("No Loudoun Segment Option")

B. Adding over 5,000 MW of generation in Virginia and Maryland

C. Reducing more than 5,000 MW of demand across the DVP zone, or over 3,000 MW in the northern Virginia area.

(16) While certain of these alternatives may be technically feasible, not all of them represent the same level of risk in terms of fruition. Some, such as the Amos–Kemptown line, rely on future transmission projects that, while approved by PJM, will be subject to siting and regulatory uncertainties that are similar to those faced by the presently proposed line, depending on the need for new transmission corridors and/or the need to cross existing conservation easements. The Meadowbrook–Doubs transmission line alternative would, in addition to the previously described siting risk, increase the reliance on Doubs – located in Maryland – as the source of even more power to flow into northern Virginia. And, albeit obvious, alternatives involving facilities located outside of Virginia are beyond the Commission's jurisdiction, and therefore outside of the Commission's direct control.

(17) A more detailed description of the above alternatives and their rationale is summarized below.

I.2.1. Transmission

(18) First, terminating the proposed line at Meadowbrook is not a feasible alternative. Most notably, this alternative will make contingency overloads *worse* on existing 500 kV lines that are located to the west and south of the Meadowbrook substation. This occurs because additional west-to-east power transfer through a new Mt. Storm–Meadowbrook path increases power flows on the existing 500 kV lines east and south of Meadowbrook substation.

(19) Second, changing the terminal substation of the proposed line from the Loudoun substation to the Doubs substation (Doubs Option) is a technically feasible alternative, although the associated routing from Meadowbrook to Doubs has not been studied. Most notably, this alternative is expected to reduce the expected loading on the Mt. Storm–Doubs line *more effectively* than the proposed Loudoun Line. This alternative runs more "parallel" to the existing Mt. Storm–Doubs 500 kV line and thereby would carry more of the power flow that would otherwise have traveled through the existing Mt. Storm–Doubs line. This alternative, however, would significantly increase the existing north-to-south power flow to serve the northern Virginia load, especially on the Doubs–Pleasant View–Loudoun line. This alternative delivers more power to the Doubs substation—and thus delivers more power to northern Virginia through the Doubs–Pleasant View–Loudoun line (north-south path) than the proposed Loudoun option, which would provide a direct 500 kV path to the northern Virginia. In short, this option makes the reliable service of northern Virginia load more reliant on Doubs. In addition, because the Doubs substation is located in Maryland, this alternative would depend on application to and approval of another State.

(20) Third, building a double-circuit 230 kV line on the Meadowbrook–Loudoun segment of the proposed Loudoun line instead of a single 500 kV line (two 230 kV option) *does not* fully resolve the reliability issues that are expected to occur in 2011. Compared to a single 500 kV line, two 230 kV lines would significantly reduce the expected power flow on the Meadowbrook–Loudoun path. As a result, this alternative would not sufficiently reduce the expected power flow on other affected "parallel" transmission lines to prevent expected contingency overloads, not only on the Mt. Storm–Doubs line, but also on the lines south of Meadowbrook–Loudoun, such as the Morrisville–Bristers and Bristers–Ox 500 kV lines. In addition, this alternative requires additional 500/230 kV transformers and a new 230 kV switchyard at the Meadowbrook substation.

(21) With additional generation, the 230 kV option would be *feasible* in 2011. Specifically, Bates White's analysis indicates that adding approximately 600 MW of generation near the Doubs substation (e.g., the three proposed Sempra gas-fired units could serve such a purpose) would make this 230 kV option feasible in terms of reliably meeting the expected 2011 system condition, even during those occasions when DVP's 736 MW Possum Point Unit #5 is unavailable (i.e., the "stressed" condition). However, based on the current understanding of the expected future system conditions, Bates White finds that this alternative is inferior to the proposed Loudoun Line option because this alternative carries significantly less power flow between Meadowbrook and Loudoun and thus is less effective in preventing the contingency overloads on other lines after 2011.

(22) Fourth, Bates White studied the Amos–Kemptown 765 kV line option (A-K 765 kV line option or A-K Option). AEP and Allegheny have proposed to build a new 765 kV line starting from the John Amos substation near St. Albans, West Virginia, to the Bedington substation. From the Bedington substation, a double-circuit 500 kV line would be extended to a new substation in Kemptown, Maryland, near the existing Doubs–Brighton and Brighton–Conastone 500 kV lines. The proposed in-service date for this facility is June 1, 2012, and the expected cost is approximately $1.8 billion. Since the planned in-service date of the proposed A-K 765 kV line is no earlier than 2012, this transmission alternative cannot resolve reliability violations expected to occur in 2011.

(23) Bates White's study indicates that if the proposed A-K 765 kV line is built by 2012, and if DVP's Possum Point Unit #5 is in service, there will be no reliability violation in 2012, even if the proposed Loudoun Line is not built. When Possum Point Unit #5 is unavailable, there will still be no reliability violation in 2012 if the 640 MW Sempra units are in service near the Doubs substation by 2012. The proposed A-K 765 kV line would carry a substantial amount of the west-to-east power flows and thus reduce resulting power flows through other west-to-east paths, *inter alia*, the Mt. Storm–Doubs line. However, this alternative does not resolve the 2011 reliability violations since the earliest in-service date for this line is year 2012. Further, as transmission projects are often delayed due to siting issues, this in-service date could be delayed by one or more years.

(24) Fifth, Bates White also studied the AC power flow control option. One way to control power flows is to install Flexible AC Transmission System (FACTS) controllers such as Phase Angle Regulators (PARs) or Unified Power Flow Controllers (UPFCs). In principle, all FACTS devices control the line impedance, voltage, current, real power, and/or reactive power by either injecting voltage in series with the line (Series Controllers) or injecting current into the line (Shunt Controllers). For example, a PAR controls the AC flow by adding a perpendicular voltage vector in series with a phase to provide a variable phase angle, thereby effectively changing the impedance of the line that it controls. A UPFC performs a similar function by combining the Series and Shunt Controllers for active and reactive power flow control. Since the expected contingency overload on the Mount Storm–Doubs line in 2011 is no more than a few hundred MW, installing a FACTS device would effectively shift this overload to less loaded lines. However, a FACTS option should be implemented judiciously (or multiple FACTS devices may be required) since it ultimately shifts (not reduces) extra power flows into other lines. This shifting of power flows may introduce new contingency overloads somewhere else as a result of an active AC power flow control.

(25) Bates White implemented a FACTS option by modeling the installation of a PAR either on the Mount Storm–Doubs line or on the Pruntytown–Mount Storm line. Bates White's study indicates that judicious PAR installation would resolve expected contingency overloads on major 500 kV lines in 2011, and the PAR option appears to be more effective if the PAR is installed on the Mt. Storm–Doubs line rather than the Pruntytown–Mt. Storm line. However, if DVP's Possum Point Unit #5 is unavailable (i.e., the "stressed" condition), the PAR option alone may not resolve the contingency overloads on major 500 kV lines that are expected to occur as early as 2011, and thus additional support from transmission, generation, and/or demand response resources is required to reliably meet the expected load growth in 2011.

I.2.2. Generation

(26) Bates White studied how much new generation would be needed to avoid the proposed Loudoun Line. Bates White's study indicates that, without the proposed Loudoun Line (or other feasible alternatives described in this report) in service by 2011, contingency overloads at various 500 kV transmission lines are expected to occur, even if 4,000 MW of capacity is added to the existing system. These contingency overloads do not disappear even if 1,600 MW of additional nuclear generation in North Anna is added on top of 4,000 MW of additional generation resources. In addition, adding new generation resources at the "wrong" location actually aggravates the severity of the expected reliability violations in 2011. Bates White also studied the *minimum* amount of new generation resources required to avoid the need of the proposed line in 2011 by hypothetically adding additional generation to the buses that are most effective in reducing the contingency overloads on the Mount Storm–Doubs line. Bates White's study indicates that the minimum generation capacity required is about 2,800 MW.

I.2.3. Demand-side management

(27) Bates White's study of demand-side alternatives to the Loudon line first had to recast the Applicants analysis of how much northern Virginia load would have to be reduced so as to avoid the need for the line. Clearly, the relatively small contribution of northern Virginia load (8%) to the Mt. Storm–Doubs overload makes any peak load reduction in the area, even an unreasonable large one, have little impact on its elimination. Because the demand growth in eastern PJM contributes more to the need for the proposed line, Bates White looked at the potential impact of PJM's load management programs in that region to reduce the need for the line. The three Base Residual Auctions for demand-side capacity held this year by PJM have shown great promise in securing load management as a resource to manage reliability in the region.

(28) Bates White’s study did not explore the potential for energy-efficiency (EE) programs for two reasons. First, it is not clear at this point how PJM or DVP would consider the contribution of EE in maintaining reliability. Further, while EE programs can often be approved and launched in a very short time, it can take years of slow progress to obtain meaningful levels of participation. This ramp-up time was considered by Bates White as limiting the feasibility of EE programs to defer the 2011 need for the proposed line.

(29) As presented in the analysis of the PJM demand-side capacity auction results, there are now well over 2,000 MW of load under direct PJM control, with a significant share of that capacity in eastern PJM. While little or none of that capacity resides in DVP territory, DVP has recently launched four demand response/load management pilots programs, some scheduled to run through 2014. Existing load under DVP control is already internalized in the DVP load forecast as discussed in the main body of the report.

(30) While Bates White’s study of load management in combination with other alternatives, based on the 2012 retool base case, is still ongoing at the time of this writing (December 2007), Bates White carried out an initial analysis of the effect the latest PJM load management capacity on the mitigation of the 2011 reliability violations. Bates White’s preliminary analysis indicates that the impact of the load management capacity in eastern PJM at the level cleared by the RPM auctions is relatively small in terms of alleviating the 2011 reliability violations. This is likely the result of higher cost eastern PJM generation resources backing down as the peak demand is decreased by load management, while the lower cost western PJM generation continues to drive the west-to-east flow across the overloaded Mt. Storm–Doubs line. Bates White’s analysis indicates that in order to eliminate the 2011 violations, it would be necessary to have over 5,000 MW of load under control across the DVP area, or over 3,000 MW in the northern Virginia zone. The latter is an impossibility, given the approximately 6,800 MW peak demand projected for 2011 for that area.

II. Introduction

II.1. Virginia Electric and Power Company and Trans-Allegheny Interstate Line Company’s applications for approval and certification of the Virginia portions of the proposed 502 Junction-Mt. Storm-Meadowbrook-Loudon 500kV transmission line

(31) On April 19, 2007, Trans-Allegheny Interstate Line Company (TrAILCo) filed with the State Corporation Commission (Commission) its Application for Approval and Certification of Electric

Facilities for the Construction of a 500 kV Transmission Line from the West Virginia-Virginia boundary in Frederick County to a point at Transmission Line #580 owned by Dominion Virginia Power in Warren County. The proposed line would enter Virginia west of Mountain Falls, Frederick County, and extend for approximately 28.1 miles to an end point at Transmission Line #580 in Warren County. The end point is approximately 300 feet west of the Appalachian Trail boundary. The TrAILCo Application also proposes to carry out modifications to the Meadowbrook Substation in Frederick County, which is owned by Allegheny Power (AP).

(32) Also on April 19, 2007, Virginia Electric and Power Company d/b/a Dominion Virginia Power (DVP), filed with the Commission on its own behalf, and on behalf of TrAILCo, (collectively, Applicants) a Joint Application for Approval and Certification of a 500 kV transmission line from a point in Warren County at Dominion Virginia Power Transmission Line #580 to Dominion Virginia Power's existing Loudoun Substation in Loudoun County. The route proposed by TrAILCo and Dominion Virginia Power would lie within or parallel to existing Dominion Virginia Power right-of-way extending for approximately 65 miles in Warren, Fauquier, Rappahannock, Culpeper, Prince William, and Loudoun Counties. In conjunction with the construction of the line, modifications would be made at the Loudoun Substation.

(33) The two 500 kV lines and associated infrastructure proposed in these two applications is the continuation of a proposed line that originates in Pennsylvania, continues through West Virginia, and terminates in Virginia. The entire proposed line is known as the 502 Junction–Mt Storm-Meadowbrook-Loudoun 500 kV transmission line (Loudoun line).

(34) Dominion Virginia Power and TrAILCo requested that their applications be consolidated, but the Commission did not consolidate the applications as one case. The authority conferred by statute requires the Commission to render a decision on the need for each segment of the line; however, the Commission ordered a joint hearing of the applications.

II.2. Statutory basis for the Commission's regulatory authority over power line siting and construction

(35) Title 56 of the Virginia Code establishes the statutory basis for public utility regulation in the Commonwealth of Virginia. Chapter 10.1 (Utility Facilities Act) § 56-265.1 states that transmission lines are public utility facilities that fall under the authority of the State Corporation Commission. Section 56-265.2 further requires that public utilities obtain a Certificate of Public Convenience and Necessity prior to construction of a transmission facility for use in public utility service, and that such a certificate, for overhead electrical transmission lines of 138 kilovolts or

more, shall be issued by the Commission only after compliance with the provisions of Section 56-46.1.

(36) Section 56-46.1 establishes that in making the determination about need, corridor, or route and method of installation, the Commission shall verify the Applicants' load flow modeling, contingency analyses, and reliability needs presented to justify the new line and its proposed method of installation. Specifically, Section 56-46.1 B establishes as a condition for approval that the Commission shall determine that the line is needed, while in subsection A the Commission is directed to consider the effect of the proposed facility on improvements in service reliability.

(37) Furthermore, the Virginia Electric Utility Restructuring Act, Chapter 23 of the Virginia Code, Section 56-580, establishes the Commission's regulatory authority, to the extent not prohibited by federal law, over the reliability, quality, and maintenance of transmission lines in Virginia.

II.3. Authority of the Commission to consider need outside of Virginia in transmission line siting determination

(38) In its June 1, 2007, Order for Notice and Hearing, the Commission directed the Staff, Dominion Virginia Power, TrAILCo, and any respondents so desiring to address the following legal issue: Does Virginia law require or permit the Commission to consider the asserted need for the facility other than the obligation to meet transmission capacity need in Virginia? Stated in other terms: Under Virginia law is the Commission permitted, or required, to consider regional, multi-state need in reviewing an application for a line in Virginia?

(39) In its response to the Commission's June 1, 2007, Order, staff listed a series of cases in which the Commission considered load and sources of supply outside of Virginia in its analyses of need. Staff further observed that the Commission has uniformly granted its approval of lines on finding that Virginia consumers benefit from the construction of the facility. Staff noted that for over 30 years the Commission has considered conditions within and without Virginia as it considered the need for proposed transmission lines. The Staff also observed that the Commission has not held that the public convenience and necessity required approval of a facility solely because of conditions outside of Virginia.

(40) While observing that the applications for approval of the Virginia portion of the 502 Junction–Mt Storm-Meadowbrook-Loudoun transmission line are the result of market changes driven by legislative and policy initiatives at the federal and state levels, in its Memorandum, the Staff recognizes that the line siting authority of the Commission is limited to that granted the Commission by Title 56 of the Virginia Code.

(41) As Virginia moved to restructure its electric sector in 2000, the siting authority granted to the Commission by Section 56-46.1 was not diminished by the passage of the Virginia Electric Utility Restructuring Act. In it, Section 56 577-A1 requires that each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity join or establish a regional transmission entity…, subject to the provisions of Section 56-579. While not applicable to TrAILCo, the Act compelled Dominion Virginia Power to join PJM with the Commission's approval. Section 56-579A2 instructed the Commission to define the terms and conditions under which DVP should join the regional transmission entity, whose purpose is to promote "[p]ractices for the reliable planning, operating, maintaining, and upgrading of the transmission systems and any necessary additions thereto…." Section 56-579-D1 expressly established that "[n]othing in this section shall be deemed to abrogate or modify [t]he Commission's authority over transmission line or facility construction, enlargement or acquisition within this Commonwealth, as set forth in Chapter 10.1 (§ 56-265.1 et seq.) of this title."

(42) The siting authority of the Commission under Section 56-46.1 is further recognized by the PJM Operating Agreement, Schedule 6, Section 1.7(a), which qualifies its members' obligations to construct transmission facilities approved in the Regional Transmission Expansion Plan subject to local siting, construction, and operating permits.

II.4. Regional Transmission Expansion Planning in the PJM RTO

(43) The PJM transmission system provides the means for delivering electricity to over 51 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. In order to ensure the continued reliability of the system, the PJM Regional Transmission Organization (RTO), in accordance with a protocol set forth in the PJM Operating Agreement,[2] carries out a regional planning process for generation and transmission expansion (in consultation with its stakeholders) that results in an annual Regional Transmission Expansion Plan (RTEP).

(44) The RTEP Protocol was initially approved by FERC in 1997, and it has been expanded and enhanced with stakeholder input through the PJM Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and the PJM Planning Committee (PC) forums. The RTEP annual planning cycle culminates in the presentation of the RTEP to the PJM Board of

[2] Regional Transmission Expansion Plan Protocol, Schedule 6, PJM Operating Agreement.

Managers for its approval.[3] Beginning in 2006, after considering significant stakeholder input, the PJM expanded the RTEP planning horizon from 10 to 15 years.

(45) In order to accomplish PJM's goals of ensuring electric supply adequacy and the establishment and operation of robust energy and capacity markets, the RTEP process brings together four complementary types of analyses: (1) baseline reliability analyses;[4] (2) generation and transmission interconnection analyses; (3) market efficiency analyses; and (4) operational performance issue reviews and analyses. Each of these analyses helps identify necessary upgrades to the transmission system.

(46) The PJM RTEP planning process ensures the reliability of the regional transmission system and applies the most stringent of the applicable NERC, PJM, or local criteria, in an annual planning cycle that extends and updates the transmission expansion plan with a 15-year horizon. Analysis is initiated in December prior to each annual cycle and concludes with review by the TEAC and approval by the PJM Board by the following October. A near-term reliability review (current year plus five) based on contingency analysis is carried out every year to identify system conditions that are at or nearing applicable criteria violations. Severe violations in any one deliverability area are referred to long-term analysis for added study of possible system enhancement. For each year between the current year plus four ("in-close" years), PJM updates and issues addenda to address changes as necessary throughout the year. Planned generation modifications or changes in transmission topology can trigger re-study and the issuance of a baseline addendum. This is referred to as a "retool" study.

(47) Each year in the RTEP process (during the establishment of the assumptions for the new annual baseline analysis) updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the "in-close" range of years to validate the continued applicability of each of the "in-close" baseline analyses and resulting upgrades (including any addenda). These assumptions are provided to and reviewed by the Subregional RTEP Committee and ultimately incorporated into the reference power flow case.

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[3] A description of the process and the roles of each of the stakeholder committees in the RTEP process can be found in PJM's Manual 14B – Section 1.

[4] Reliability analyses include reference system voltage and thermal analysis and stability, load deliverability, and generation deliverability testing.

II.5. Purpose and organization of this report

(48) The purpose of this report is to present the findings of the independent review of the applications for approval and certification of electric facilities filed by TrAILCo and by Dominion Virginia Power, for the Virginia portion of the 502 Junction-Mt. Storm-Meadowbrook and the Meadowbrook-Loudoun 500 kV transmission lines.

(49) As the consultant to the Commission Staff, Bates White, LLC, was retained to independently review and verify the Applicants' load flow modeling, contingency analyses, and reliability needs presented to justify the new line and its proposed method of installation as required by Section 56-46.1 B of the Virginia Code.

(50) In order to satisfy these objectives, Bates White set out to:

A. Assess the reasonableness and consistency of the modeling assumptions and data inputs in the DVP, TrAILCo, and PJM Base Cases in terms of generation, load, and transmission; the reasonableness of the proposed line (with respect to timing, reliability, and previous RTEP); and the impact and significance of the PJM 2007 RTEP update;

B. Assess the reasonableness and consistency of the DVP, TrAILCo, and PJM power flow studies by preparing and conducting contingency analyses, including acquiring, validating and integrating necessary data inputs, modeling assumptions, and load flow cases; conducting contingency analyses to determine reliability needs based on NERC, PJM, and DVP planning criteria; and classifying and summarizing relevant limiting facilities and contingency elements;

C. Assess and identify feasible demand-side, generation and/or transmission alternatives to satisfy northern Virginia reliability needs, thus postponing or eliminating the need for the proposed line;

D. Investigate factors external to Virginia driving the need for the proposed line, identifying what actions (if any) could be taken to mitigate the need for the line;

E. Independently assess the reasonableness of DVP/TrAILCo transmission project cost estimates; including right-of-way/easement cost.

(51) The balance of the report is organized as follows: Chapter 3 presents a brief description of the Applicants' proposed Loudoun Line, followed by the current and expected power supply situation in northern Virginia and the transmission loading situation of the existing grid. Chapter 4 describes Bates White's independent determination of need study, starting with a description of Bates White's approach and methodology, followed by the analysis of reasonableness and

consistency of Applicants' load flow base cases and the comparison of Bates White's analysis results with the Applicants' reliability need assessment. Chapter 5 describes the alternatives studied by Bates White. Three general categories of alternatives (and combinations thereof) were considered: i.e., transmission, generation, and demand response. The comparative merits of these alternatives with respect to the proposed Loudoun Line were also summarized. Chapter 6 summarizes the conclusion of this report.

III. Description of the proposed transmission line

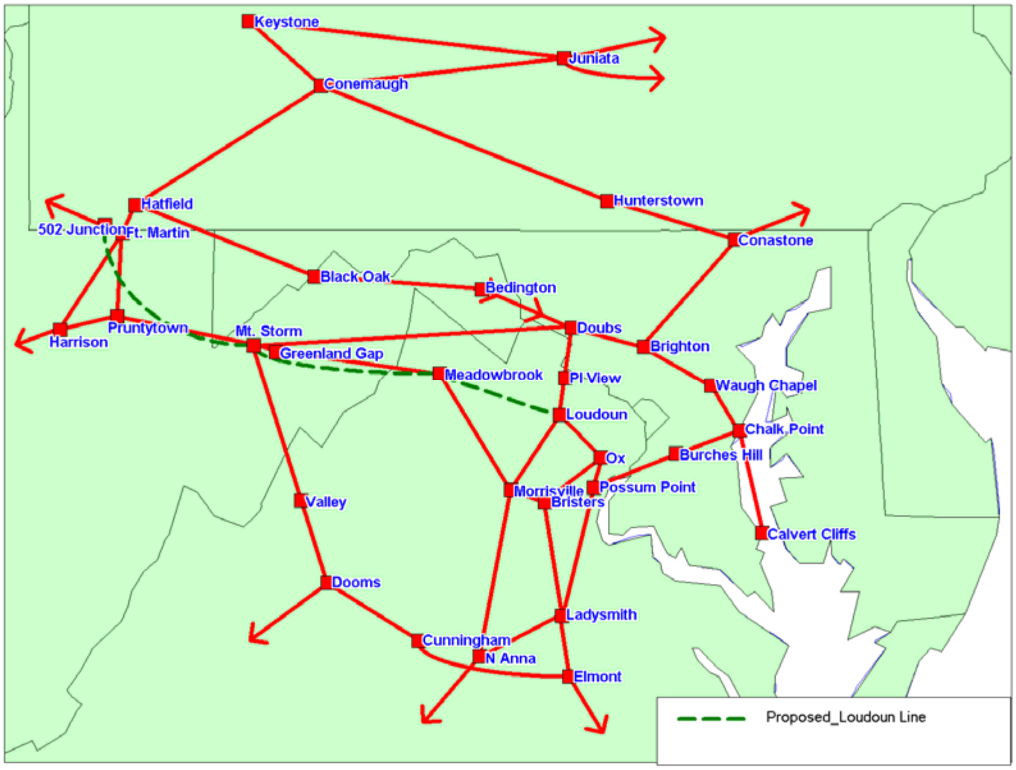
III.1. Description of the Applicants' proposed transmission line

(52) TrAILCo proposes to build a 500 kV transmission line from the West Virginia-Virginia boundary in Frederick County to a point at Transmission Line #580 owned by Dominion Virginia Power in Warren County. The proposed line would enter Virginia west of Mountain Falls, Frederick County, and extend for approximately 28.1 miles to an end point at Transmission Line #580 in Warren County. TrAILCo also proposes to carry out modifications to the Meadowbrook Substation in Frederick County.

(53) DVP proposes to build a new 500 kV transmission line beginning near the Meadowbrook substation in Frederick County, Virginia, and extending to DVP's existing Loudoun substation in Loudoun County, Virginia. The length of the proposed transmission line is approximately 65 miles.

(54) The proposed lines are part of a larger 500 kV transmission line beginning near AP's 502 Junction substation in southern Pennsylvania and extending to DVP's Loudoun substation, with intermediate connections at both DVP's Mount Storm substation in West Virginia and AP's Meadowbrook substation. This entire project is referred to as the 502 Junction–Mt. Storm–Meadowbrook–Loudoun Line or, in short, Loudoun Line. The total length of the Loudoun Line is proposed to be approximately 265 miles. Exhibit 1 shows the proposed Loudoun Line and existing 500 kV transmission system.

Exhibit 1: Proposed Loudoun Line and existing 500 kV transmission system



III.2. Power supply situation in northern Virginia

(55) The proposed Loudoun Line is designed to enhance reliability of the PJM system, particularly for the mid-Atlantic region and northern Virginia. Without significant increases in new generation and/or demand response in the mid-Atlantic region and northern Virginia, this area will require an increase in import capabilities in order to reliably meet expected future growth in demand.

(56) For example, DVP's northern Virginia load had an actual summer peak of 6,368 MW in 2006, and the summer peak is expected to grow to 6,833 MW in 2011.[5] However, northern Virginia only has about 2,900 MW of generation.[6] Therefore, in the absence of new generation and demand response, northern Virginia will need about 4,000 MW of power imports from remote generation to serve its load in 2011 under normal (no contingency) conditions. When DVP's 736 MW Possum Point Unit #5 is unavailable, northern Virginia's dependence on imports is even

[5] Attachment I.B.3.

[6] Dominion: Meeting Northern Virginia's Growing Demand for Electricity, at 3.

greater. Secure imports from outside northern Virginia thus are asserted by the Applicants to be critical to meet expected load growth.

III.3. Transmission loading situation of the existing grid

(57) There are five 500 kV lines that provide west-to-east power transfers to northern Virginia and the mid-Atlantic region of the PJM. They are (1) Conemaugh–Hunterstown–Conastone; (2) Black Oak–Bedington–Doubs; (3) Mount Storm–Doubs; (4) Mount Storm–Greenland Gap–Meadowbrook; and (5) Dooms–Cunningham–Elmont. In 2011, the approximate amount of west-to-east power flow on these lines is expected to be 8,630 MW.[7] This west-to-east power flow increases to 8,780 MW (a 150 MW increase) when DVP's 736 MW Possum Point Unit #5 is unavailable. Such a generation unit outage assumption is referred to as a "stressed" condition. Exhibit 2 and Exhibit 3 show the expected amount of power flows on these lines in 2011 with and without DVP's Possum Point Unit #5.

[7] Unless otherwise specified, all reported power flows were measured from the "To Bus." For example, reported power flows on the Mount Storm-Doubs line are measured from the Doubs line.

Exhibit 2: Expected power flows in 2011 on existing 500 kV transmission lines with Possum Point Unit #5

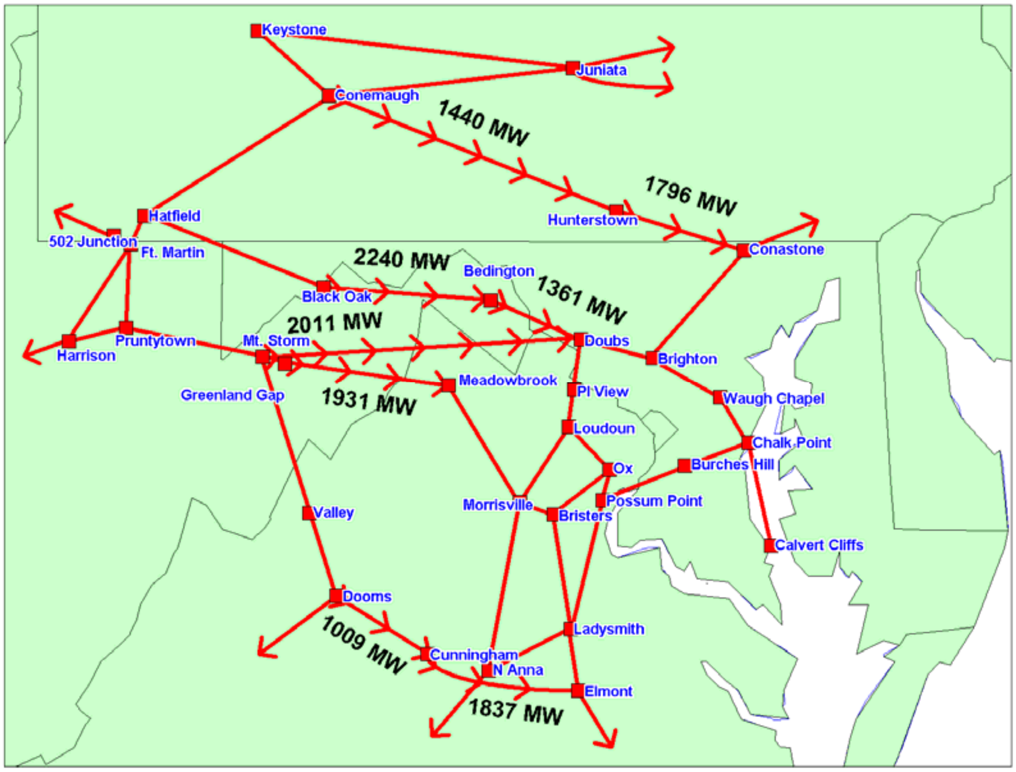
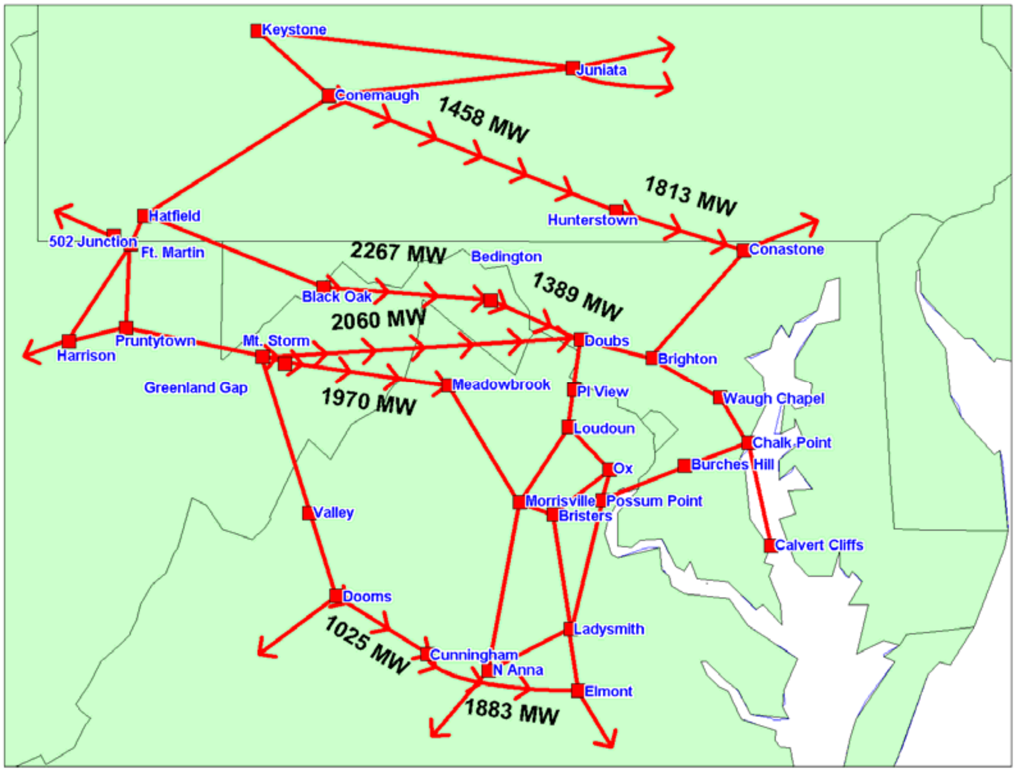


Exhibit 3: Expected power flows in 2011 on existing 500 kV transmission lines without Possum Point Unit #5



(58) Some of these 500 kV lines (Black Oak–Bedington–Doubs, Mount Storm–Doubs, and Mount Storm–Meadowbrook) have been significant operating constraints in the past. For example, the Black Oak–Bedington–Doubs line, while thermally limited to 3,502 MVA, was effectively operated significantly below the thermal limit because the voltage limit was reached before the thermal limit.

(59) The Mount Storm–Doubs line was load-restricted for 555 hours in 2005. In response, DVP accelerated its planned upgrade of the line by four years, from 2010 to 2006. This upgrade increased the thermal capability of this line from 2,200 MVA to its current rating of 2,598 MVA.

(60) These 500 kV related operational constraints not only cause inefficient dispatch of generation (generally by reducing outputs from cheaper generation in PJM West and increasing outputs from more expensive generation in PJM East) but also impair PJM’s capability of reliably meeting the expected peak load growth, especially in the PJM mid-Atlantic region and the northern Virginia area. These operational constraints on existing 500 kV lines indicate a need that must be addressed in transmission planning.

IV. Independent determination of need

IV.1. Description of approach and methodology

(61) As a "needs" consultant to the Commission Staff, Bates White was contracted to independently verify the reliability needs presented by the Applicants to justify the construction of the proposed Loudoun Line.

(62) To achieve this purpose, Bates White has collected, integrated, and validated the data needed for transmission modeling of expected 2011 and 2016 system conditions. Based on these data, Bates White has conducted the power flow analysis to independently determine the need of the line.

(63) Bates White has applied NERC reliability standards and DVP planning criteria in its study. In doing so, Bates White has incorporated both the national and the local reliability standards in its independent determination of the need for the proposed Loudoun Line. The following subsections briefly describe the NERC reliability criteria, the DVP planning criteria, the PJM deliverability criteria, and the reliability criteria used in the Bates White study.

IV.1.1. National, regional, and local reliability criteria

IV.1.1.1. NERC National Reliability Standards

(64) As of June, 2007, all U.S. electric transmission operators must plan and operate their systems under mandatory, enforceable reliability standards. Utilities and other bulk power industry participants that violate any of the 83 standards will face enforcement actions including possible fines of up to $1 million a day.[8] The North American Electric Reliability Corporation (NERC), previously known as the North American Electric Reliability Council, is responsible for developing and enforcing these standards as one means of improving the reliability of North America's bulk power system.[9]

(65) The electricity industry has had planning and operating criteria and guidelines for decades, but compliance was always voluntary. The notable exception was PJM. Since the start of the RTEP process, PJM has been applying the NERC reliability standards and its deliverability criteria on a

[8] Examples of penalties for standards violations include sanctions that impose limitations or restrictions on activities; remedial action directives designed to correct conditions, practices or other actions posing a threat to reliability; and fines of $1,000 to $1 million per day. Penalties will be commensurate with the severity of the violation. Other factors taken into consideration may include the risk to the grid, whether the organization self-reported, the timeliness of reporting if self-reported, the relative size of the organization, and the quality of the mitigation plan.

[9] The bulk power system consists of the power plants, transmission lines and substations, and related equipment and controls, that generate and move electricity in bulk to points from which local electric companies distribute the electricity to customers.

mandatory basis. The August 2003 blackout that affected 50 million people in the northeastern and mid-western United States and Canada prompted U.S. legislators to make standards mandatory via the Energy Policy Act of 2005.[10] On March 16, 2007, FERC issued a final rule on Mandatory Reliability Standards for the Bulk-Power System.[11]

(66) A reliability standard defines obligations or requirements of utilities and other entities that operate, plan, and use the bulk power system in North America. Meeting these requirements helps ensure the reliable planning and operation of the bulk power system. Each NERC Reliability Standard details the purpose of the standard, the entities that must comply, the specific actions that constitute compliance, and how the standard will be measured.

(67) In Order No. 693, FERC delegated the authority to develop and enforce mandatory standards to NERC, a self-regulatory organization, supported by eight regional organizations that represent the entire North American continent. While the process of monitoring and enforcing standards will vary slightly for the United States and each Canadian province, electric transmission utilities in all regions of North America must plan and operate their systems in accordance with the NERC standards.

(68) Standards address aspects of the operation and planning of the bulk power system such as the following:

- BAL: Resource and Demand Balancing
- CIP: Critical Infrastructure Protection
- COM: Communications
- EOP: Emergency Preparedness and Operations
- FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities
- INT: Interchange Scheduling and Coordination
- IRO: Interconnection Reliability Operations and Coordination
- MOD: Modeling, Data, and Analysis
- PER: Personnel Performance, Training and Qualifications
- PRC: Protection and Control

[10] Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), to be codified at 16 U.S.C. 824o.

[11] 18 C.F.R. Part 40 (Docket No. RM06-16-000; Order No. 693) Mandatory Reliability Standards for the Bulk-Power System (March 16, 2007)

- TOP: Transmission Operations
- TPL: Transmission Planning
- VAR: Voltage and Reactive Control

(69) The Standards detail how the system should perform, but not how the system should be designed. It is important to note that individual owners, operators, and users of the bulk power system determine if, and how, the system should be expanded or changed in order to achieve the standards. For purposes of transmission planning, the TPL Standards are the most relevant. The TPL Reliability Standards address: (1) the types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs and (2) the information required to assess regional compliance with planning criteria and for self-assessment of regional reliability. Specifically, the Transmission Planning (TPL) group of Reliability Standards consists of six Reliability Standards that are applicable to transmission planners, planning authorities, and regional reliability organizations. These Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including the following:

- Developing a model of the Bulk-Power System
- Using this model to assess the performance of the system for a range of operating conditions and contingencies
- Determining those operating conditions and contingencies that have an undesirable reliability impact
- Identifying the need and alternatives, and selecting the preferred solution, taking into account, *inter alia*, the time needed to place the solution in service

(70) The TPL group of Reliability Standards contains a table designated “Table 1” (Transmission System Standards–Normal and Emergency Conditions) that is a key part of this group of Reliability Standards. It lays out the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency.

- “Category A” (TPL-001-0) applies to the normal system with no contingencies.

- “Category B” (TPL-002-0) applies to contingencies resulting in the loss of a single element, defined as a generator, transmission circuit, transformer, or a single DC pole with or without a fault. This is referred to as the “N-1” criterion.
- “Category C” (TPL-003-0) applies to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple circuit tower line or both poles of a bi-polar DC line.[12] This is referred to as the “N-2” criterion.[13]
- “Category D” (TPL-004-0) applies to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way.
- Exhibit 4 reproduces NERC TPL “Table 1” (Transmission System Standards–Normal and Emergency Conditions).

[12] The system performance expectations for Category C contingencies are lower than those for Category B contingencies in that they allow unspecified amounts of planned or controlled loss of load.

[13] Dominion Virginia Power uses N-1-1 criteria for the “stressed” system condition that effectively reflects the loss of two elements much like the N-2 criteria. N-1-1 differs in that it assumes that the loss of one element was known with operational adjustments while the loss of the second element was unexpected.

Exhibit 4: NERC TPL "Table 1" (Transmission System Standards–Normal and Emergency Conditions)

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

IV.1.1.2. DVP Local Reliability Criteria

(71) DVP uses the following criteria in planning its transmission system. Additionally, DVP makes an allowance of 6% in circuit loading (i.e., 94% loading, instead of 100% loading) to accommodate

weather and load forecast uncertainties.[14] DVP's criteria include, among other things, the following:[15]

A. The loss of any one transmission circuit should not cause the maximum continuous rating to be exceeded on any of the remaining transmission facilities, nor should it cause the loss of any load, other than the load connected to that circuit.

B. The loss of any two transmission circuits on a common right-of-way should not result in cascading outages or loss of load, other than that connected to the two circuits.

C. The transmission system should be capable of supplying peak loads without exceeding the maximum continuous rating on any facility when the following conditions occur:

   1. The outage of the two largest generators in any generating station when all transmission facilities are in service

   2. The outage of the largest generator in any generating station and the loss of the most critical transmission facility (the one that studies show has the greatest effect on the area)

D. During the above generation outages, other DVP generating sources would be adjusted to make up the deficiency to the limit of available capacity.

E. The reliability requirements described in Table 1 of NERC Reliability Standards TPL-001-0 through TPL-004-0 must be met, at a minimum.

(72) In summary, according to DVP's planning criteria (which are based on the NERC reliability standards), DVP plans its transmission system so that: (a) for a loss of a critical transmission line or a transformer while the largest generating unit in the area is also unavailable, no transmission facility should be loaded above 94% of its emergency thermal rating, and (b) during the above generation outages, other DVP generating sources would be adjusted to make up the deficiency to the limit of available capacity. In essence, DVP has implemented "N-1-1" criteria in its transmission system planning.

IV.1.1.3. PJM Regional Reliability Criteria

(73) Attachment E of the PJM Manual 14B: PJM Regional Planning Process describes the PJM regional planning criteria.[16] In addition to abiding to NERC and RFC Reliability Criteria,[17] PJM

[14] DVP uses "normal" weather and 50/50 load forecasting for purposes of the transmission planning studies.

[15] Facility Connection Requirements, Exhibit A, Planning Guidelines (May 29, 2007).

[16] Attachment E of the PJM Manual 14B: PJM Regional Planning Process. http://www.pjm.com/contributions/pjm-manuals/pdf/m14b.pdf

also performs load deliverability and generator deliverability tests to evaluate the system reliability of the PJM regional transmission system.

- A Load Deliverability Test measures the transmission system's capability to deliver energy from the aggregate of all capacity (generation) resources to an electrical area experiencing a capacity deficiency.
- A Generator Deliverability Test measures the capability of the transmission system to deliver energy from the aggregated output of generators in a given area to the rest of PJM.

(74) As part of its ongoing responsibility to reliably operate the transmission system, PJM prepares a Regional Transmission Expansion Plan (RTEP) that consolidates the transmission needs of the region into a single plan. The RTEP base case model reflects transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing five years. The RTEP base case model is updated yearly, at a minimum, based on historical data that are discussed and approved at the PJM Planning Committee prior to implementation.

IV.1.1.4. Reliability Criteria used in Bates White study

(75) Bates White has applied the DVP planning criteria, which incorporate the NERC reliability standards. Specifically, Bates White has performed the NERC n-1 contingency analysis for both 2011 and 2016 forecasted system conditions, assuming that DVP's Possum Point Unit #5 is in service (i.e., normal condition) or out of service (i.e., the "stressed" condition). In doing so, Bates White has incorporated both the national and the local reliability standards in its independent determination of the need for the proposed Loudoun Line. The following subsections briefly describe the contingency analysis, which is a power flow analysis that incorporates the NERC reliability criteria.

IV.1.2. Overview of contingency analysis

(76) All power system networks have three major components: generation, transmission, and load.[18] Generation creates power, load consumes power, and transmission conveys power from generation to load. Power flow network models refer to these as: sources, sinks, and paths, respectively. Each source and sink of a network defines a node in the network. A node is called bus in electric power networks. Each transmission circuit between two adjacent busses defines a

[17] RFC includes MAAC, ECAR, and MAIN regions of NERC.

[18] Unless otherwise specified, power system (analysis, flow, etc) means electric power system (analysis, flow, etc) throughout this report.

branch in the network. A branch is called a path in electric power networks. Thus, generated power enters the network at sources, travels though the network on paths, and leaves the network to supply loads at sinks. Busses are located in substations and switching stations, the fenced-in areas easily recognized at the ends of transmission lines.

(77) All power flows through paths are said to have a “non-local” effect. This is because power flowing through any particular path generally has an effect (to varying degrees) on power flows in all other paths of the network. This non-local effect is particularly manifest in what are called “loop flows” or “parallel flows” where power flowing between two busses transits multiple network routes (each route generally being composed of a number of paths). Usually, only one of those network routes is the “contract path” for a power transfer.

(78) In order to ensure power system reliability, i.e., with power systems operating such that system overloads do not occur (either in real time or under probabilistic contingency conditions), the resulting power transfer should not overload the power system during or after an occurrence of contingencies, as defined in accordance with the comprehensive reliability criteria established by the NERC.

(79) Contingencies can be either simple (such as an outage of a single transmission line or a generator, e.g., N-1 contingency) or complex (such as the simultaneous loss of multiple transmission lines and/or generators, e.g., N-2 contingency).

(80) Exhibit 5 and Exhibit 6 illustrate power transfer results from bus 1 to bus 2 with and without the N-1 contingency condition, respectively. Without the N-1 contingency condition, the amount of power transfer from bus 1 to bus 2 is approximately 1,725 MW (i.e., the sum of 690 MW and 1,035 MW, as shown in Exhibit 5). However, under an n-1 contingency condition (i.e., the loss of a single transmission line between bus 1 and bus 2), the resulting power transfer value is approximately 690 MW (as shown in Exhibit 6), which is only about 40% of the power transfer value without the N-1 contingency case.

(81) The resulting power transfer values depend critically on both the data inputs (e.g., the solved power flow case and the list of monitored and contingency elements) and the modeling assumptions (e.g., which and how much of generators and/or loads participate) used in conducting the contingency analysis.

Exhibit 5: Illustrative power flow results without N-1 contingency condition

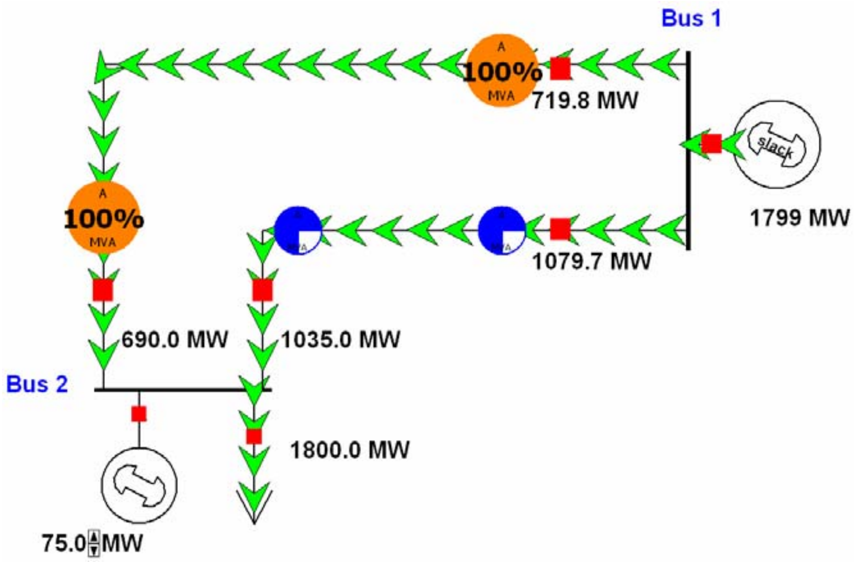
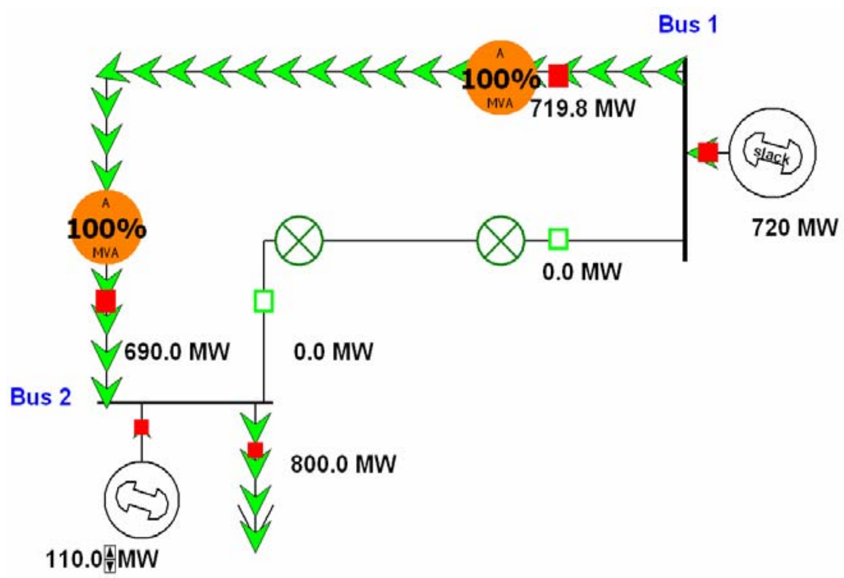


Exhibit 6: Illustrative power flow results with N-1 contingency condition



(82) All Contingency Analyses require two data inputs: a solved power flow case and a list of contingencies and monitored elements. A solved power flow case models the network topologies and power system conditions during the time period being studied (e.g., the on-line and off-line units, base transfers among control areas, and output levels of generators and loads, etc.). A properly constructed power flow case is essential in presenting the most appropriate characterization of the power system condition, because of “built-in” (or embedded)

representations of how and how much generation and load are dispatched and electrically distributed in the transmission system under study.[19] A list of contingencies and monitored elements is necessary to ensure system "security," i.e., with power systems operating in such a way that system overloads do not occur either in real time or under any N-1 contingency condition.

(83) The following section describes Bates White's analysis of the reasonableness and consistency of the Applicants' power flow cases. It is important to note that the Applicants have the first-hand knowledge of their transmission system. Therefore, Bates White's analysis is limited to checking the overall reasonableness and consistency of the data and information provided by the Applicants.

IV.2. Analysis of reasonableness and consistency of Applicants' power flow cases

IV.2.1. Overview of Applicants' power flow cases

(84) In response to Staff's data requests, DVP, KEMA, and PJM have provided dozens of power flow cases that they have used in the proposed Loudoun Line Application.[20] As described more fully below, since the DVP-provided power flow cases are more updated than the KEMA-provided ones, and KEMA's power flow cases did not redispatch the generation in accordance with the DVP's planning criteria when Possum Point Unit #5 is unavailable, Bates White adopted the DVP-provided power flow cases and associated data inputs such as monitoring and contingency files as a basis for its study.[21] Exhibit 7 lists the name and the description of the DVP-provided power flow cases:

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[19] Electric distributions (or sensitivities) of generation and load over power transfers are measured by various distribution factors. For example, Power Transfer Distribution Factors ("PTDF") measure the impact of a single power transfer on many transmission lines; Generation Shift Factors ("GSF") measure the impact of many power transfers on a single transmission line; Line Outage Distribution Factors ("LODF") measure the impact of a single line outage on many transmission lines; and Outage Transfer Distribution Factors ("OTDF") measure the percentage power flow changes on many transmission lines because of a single transmission line outage. A solved power flow case essentially predetermines the above-listed distribution factors. This fact is important because a resulting contingency analysis outcome is highly dependent on them.

[20] TrAILCo stated that it used the PJM power flow cases in the application.

[21] The name of the monitoring and contingency files are *vapsys.mon* and *VapsysNORT.con*, respectively.

Exhibit 7: List and Description of the DVP-provided power flow cases

Power Flow Case / File Name	Description	Comments
S2011_11_13_2006v29nline.raw	Summer 2011 Power Flow Case based on 2006 Load Forecast	Does not include the proposed Loudoun 500 kV Line.
s2011_11_13_2006v29nlinenppt5v29.raw	Summer 2011 Power Flow Case based on 2006 Load Forecast	Does not include the Loudoun Line; No Possum Point Unit #5
S2011_2007Forecastv29nline.raw	Summer 2011 Power Flow Case based on 2007 Load Forecast	Does not include the proposed Loudoun 500 kV Line.
S2011_2007Forecastv29nlinenppt5v29.raw	Summer 2011 Power Flow Case based on 2007 Load Forecast	Does not include the Loudoun Line; No Possum Point Unit #5
S2016_02-22-07nolinev29.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	Does not include the proposed Loudoun 500 kV Line.
S2016_02-22-07nolinenppt5v29.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	Does not include the Loudoun Line; No Possum Point Unit #5
s2011_11-13-2006v29pref.raw	Summer 2011 Power Flow Case based on 2006 Load Forecast	Does include the proposed Loudoun 500 kV Line.
s2011_11-13-2006v29prefnppt5.raw	Summer 2011 Power Flow Case based on 2006 Load Forecast	Does include the Loudoun Line; No Possum Point Unit #5
s2011_forecast_2007_v1v29pref.raw	Summer 2011 Power Flow Case based on 2007 Load Forecast	Does include the proposed Loudoun 500 kV Line.
s2011_forecast_2007_v1v29prefnppt5.raw	Summer 2011 Power Flow Case based on 2007 Load Forecast	Does include the Loudoun Line; No Possum Point Unit #5
S2016_02-22-07nolinev29pref.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	Does include the proposed Loudoun 500 kV Line.
S2016_02-22-07nolinev29prefnppt5.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	Does include the Loudoun Line; No Possum Point Unit #5
S2016_02-22-07i66route.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	Meadowbrook to Loudoun I66 Route
S2016_02-22-07nolinev29nppt5502jctmtstm.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	No Possum Point Unit #5 Build 502 JCT to Mount Storm
S2016_02-22-07nolinev29nppt5502jctmtstmmb.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	No Possum Point Unit #5 Build 502 JCT to Mount Storm to Meadowbrook
S2016_02-22-07nolinev29nppt5mbdoubs.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	No Possum Point Unit #5 Build 502 JCT to Mount Storm to Meadowbrook to Doubs
S2016_02-22-07nolinev29nppt5mtstmbedkemp.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	No Possum Point Unit #5 Build 502 JCT to Mount Storm to Bedington to Kemptown
S2016_02-22-07nolinev29nppt5naloud.raw	Summer 2016 Power Flow Case based on 2007 Load Forecast	No Possum Point Unit #5 Build North Anna to Loudoun

(85) Among the DVP-provided power flow cases, Bates White has adopted those with 2007 load forecasts as a basis for its base case development for the following two reasons:

- 2007 load forecast cases contain more updated information on PJM load forecasting.
- 2007 load forecast cases only redispatch generators in DVP zone when the Possum Point Unit #5 is unavailable in accordance with the DVP planning criteria. By contrast, 2006 load forecast cases—like KEMA's power flow cases—redispatch generators throughout the entire

PJM region when Possum Point Unit #5 is unavailable; this is not consistent with the DVP planning criteria.

(86) The following subsection compares the impact of DVP and PJM redispatch methodologies on the resulting contingency overloads on various transmission lines.

IV.2.2. Comparing DVP and PJM redispatch methodology

(87) DVP's 2006 load forecast power flow cases model the "stressed" condition by redispatching the entire PJM generation to make up for the loss of Possum Point Unit # 5. By contrast, DVP's 2007 load forecast power flow cases model the stressed condition by redispatching the generation in the DVP area. Since the generation output level critically affects the results of the contingency analysis, Bates White performed an analysis to determine the impact of a different redispatch assumption.

(88) Specifically, Bates White created two different power flow cases based on the same power flow case that models the 2011 system condition using 2007 PJM load forecast data. The only difference between the two power flow cases is the redispatch assumption: i.e., the entire PJM generation was redispatched in one case, and only DVP generation was redispatched in the other case.

(89) Exhibit 8 compares the impact of different redispatch assumptions on the resulting contingency overloads.

Exhibit 8: Comparison of impact of PJM and DVP redispatch assumption on the resulting contingency overloads (2011 system condition)

Contingency	Overload	kV	Rating (MVA)	DVP Redispatch (%)	PJM Redispatch (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.0	101.0
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.0	100.7
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.5	95.3
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.6	111.3
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	110.6
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	104.7	105.9
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.3	104.0
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	95.5
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.6	120.2
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.8	117.8
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.4	100.6
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	148.1	147.4
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	94.5	95.0
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	144.6	142.7
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	113.6	112.1

(90) It turns out that the PJM redispatch methodology makes contingency overloads in the Pruntytown–Mt. Storm line worse than the DVP redispatch case at the loss of either the Hatfield–Black Oak or Black Oak–Bedington 500 kV lines.[22] The reason is that the PJM redispatch methodology increases generation in PJM West, while the DVP redispatch methodology does not. For other contingencies, the resulting overloads are comparable between the two different redispatch assumptions such as contingency overloads on the Mount Storm–Doubs 500 kV line. This is a counter-intuitive result since the PJM redispatch methodology increases generation in PJM West, and thus increases loading on the Mount Storm–Doubs 500 kV line that carries west-to-east power flow. This seemingly counter-intuitive result can be explained by the fact that some

[22] Another notable difference is that when DVP generation is used to make up the loss of the 736 MW Possum Point #5 unit, Bristers–Ox 500 kV line becomes 96% loaded at a loss of the Loudoun–Morrisville 500 kV line, while the PJM redispatch assumption yields the less than 94% loading on the same line under the same contingency condition.

of the DVP generation also increases loading on the Mount Storm–Doubs 500 kV line. These two opposite effects provide similar adverse impacts on the Mount Storm–Doubs 500 kV line contingency loading. Thus, Bates White concludes that different redispatch assumptions have minimal impact in determining the need for the proposed line.

(91) The following subsection compares DVP's 2006 and 2007 load forecast power flow cases.

IV.2.3. Comparing DVP's 2006 and 2007 Load Forecast power flow cases

(92) As noted above, DVP has provided power flow cases implemented for the 2006 and 2007 load forecasts. In the 2011 system condition, DVP and AP area total load in the 2007 load forecast power flow case are approximately 510 MW and 530 MW higher than the 2006 load forecast power flow case, respectively. In terms of generation, DVP and AP area total generation in the 2007 load forecast power flow case are approximately 600 MW and 1,600 MW higher than the 2006 load forecast power flow case, respectively. These differences in total generation and load come from, *inter alia*, (a) the difference in 2006 and 2007 load forecasting; and (b) the difference in redispatch methodology when Possum Point Unit # 5 is unavailable. It is important to note that—similar to KEMA's power flow case—DVP's 2006 load forecast power flow cases used the entirety of PJM generation to make up the Possum Point Unit # 5unavailability. By contrast, DVP's 2007 load forecast power flow cases used DVP zone generation only to make up the loss of Possum Point Unit # 5, in accordance with the DVP's planning criteria.

(93) Exhibit 9 compares the combined impact of differences in load forecasting (i.e., 2006 versus 2007 load forecasting) as well as the different redispatch assumptions (i.e., PJM regional redispatch versus DVP zone redispatch) on the resulting contingency overloads.

Exhibit 9: Comparison of the combined impact of differences in load forecasting and redispatch assumptions on the resulting contingency overloads (2011 system condition)

Contingency	Overload	kV	Rating (MVA)	2007 load forecasting case (%)	2006 load forecasting case (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.0	
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.0	
MT STORM DOUBS	Mount Storm – Greenland Gap	500	2598		99.8
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.5	
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.6	103.5
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	103.5
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	104.7	101.7
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.3	101.0
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.6	108.0
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.8	107.9
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.4	95.8
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	148.1	113.9
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	94.5	
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	144.6	113.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	113.6	94.0

(94) As expected, the 2007 load forecasting makes contingency overloads worse than the 2006 load forecasting case. For example, contingency overloads on the Pruntytown–Mt. Storm line at the loss of either the Hatfield–Black Oak or Black Oak–Bedington 500 kV lines are non-existent in the 2006 load forecasting case. Similarly, contingency overloads on the Bristers–Ox and Morrisville–Bristers lines are similarly absent in the 2006 load forecasting case. However, there is a contingency overload on the Mount–Storm–Greenland Gap 500 kV line at a loss of Mount Storm–Doubs line in the 2006 load forecast case; this contingency overload is absent in the 2007 load forecasting case.

(95) Unless otherwise specified, the balance of this report only shows the outcomes based on the 2007 load forecasting power flow cases that model expected 2011 and 2016 system conditions for normal and “stressed” system conditions. This is because the 2007 load forecasting power flow

cases provide more updated system information and model the "stressed" system condition in accordance with the DVP planning criteria, i.e., redispatching generation in the DVP area when Possum Point Unit # 5 is unavailable.

IV.3. Comparison of Bates White's findings with Applicants' Reliability Need Assessment

(96) For purposes of supporting a proposed Loudoun Line, PJM, TrAILCo, KEMA, and DVP performed independent studies to assess the existing system's ability to reliably meet the expected demand growth in the PJM region and the northern Virginia area.

(97) The PJM study supporting the applications identifies 11 reliability violations that could occur beginning in 2011 and one electric reliability problem that could occur beginning in 2014 if the proposed line is not built. Eight instances of the expected reliability violations occur on the Mount Storm–Doubs line, one electrical occurrence makes the expected loading on the Pruntytown–Mount Storm 500 kV line exceed its emergency rating, and three NERC N-2 contingency conditions (i.e., NERC TPL-003-0) cause voltage problems around TrAILCo's Meadowbrook substation.

(98) The KEMA study supporting the applications concludes that without additional system improvements, the existing system will experience reliability violations as early as 2011. Major expected contingency overloads could occur by 2011 on the Mount Storm–Doubs, Hatfield–Black Oak, and Black Oak–Bedington 500 kV lines. By 2016 violations would be expected to occur on the above listed three lines plus the Bristers–Ox, Bristers–Morrisville, Dooms–Lexington, and Cunningham–Elmont 500 kV transmission lines.

(99) The DVP study also concludes that without additional system improvements, there will be reliability violations on the major 500 kV transmission lines by as early as 2011. Based on the NERC and DVP reliability criteria, these expected contingency overloads indicate a need to expand the existing transmission system. Since all of the studies listed above indicate similar or the same expected contingency overloads, it is not practical to verify the results of the all studies. Therefore, Bates White has focused on verifying the studies performed by DVP. Another advantage of focusing on the DVP study is that since DVP's own analysis applied the local DVP planning criteria in establishing the need for the proposed line, and DVP would apply its own reliability criteria regardless of its participation in PJM RTO, Bates White was able verify the need for the proposed Loudoun Line from a local perspective.

(100) Attachments I.B.4 and I.B.5 of DVP's Application provide a summary of expected contingency overloads in 2011 and 2016 system conditions with Possum Point #5 on and off, respectively. Bates White ("BW") has conducted NERC N-1 contingency analyses to verify the DVP analysis and to independently assess the need of the proposed Loudoun Line. The following subsections compare the major NERC reliability violation results.

IV.3.1. No Loudoun Line with Possum Point #5 in 2011

(101) Exhibit 10 compares the Bates White and DVP lists of expected major contingency overloads in 2011 when the proposed Loudoun Line is not built.[23]

Exhibit 10: List of expected major contingency overloads in 2011 when the proposed Loudoun Line is not built

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.7	94.5
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.5	94.5
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	108.1	104.3
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	101.9	101.8
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	108.8	105.1
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm – Doubs	500	2598	103.2	101.9
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	115.4	116.1
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	99.1	
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	117.0	117.3
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	109.0	
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	141.4	143.4
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	137.8	140.6

(102) Specifically, both the BW and the DVP contingency analyses show major reliability violations on the Mt. Storm–Doubs 500 kV line due to the loss of the Mt. Storm–Greenland Gap, Black Oak–Bedington, Greenland Gap–Meadowbrook, or Hatfield–Black Oak 500 kV transmission lines. The projected overloads on the Mt. Storm–Doubs line range between 102% and 109% in the BW analysis and between 102% and 105% in the DVP analysis.

(103) Therefore, both the BW and DVP contingency analyses show that there is a need to improve the existing grid in order to reliably meet expected load in 2011.

[23] The name of the power flow case is *S2011_2007Forecastv29nline.raw*, which was provided by DVP in response to Staff Data Request 2-12. The source of the DVP list of expected contingency overloads is Attachment I.B.4.

IV.3.2. No Loudoun Line with Possum Point #5 in 2016

(104) Exhibit 11 compares the BW and DVP lists of expected major contingency overloads in 2016 if the proposed Loudoun Line is not built. This case assumes that proposed Amos–Kemptown Line (A-K Line) and many other RTEP transmission improvements that are expected to be in service after 2011 but before 2016 would not be built by 2016.[24]

Exhibit 11: List of expected major contingency overloads in 2016 if the proposed Loudoun Line is not built

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	108.2	110.9
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	108.6	109.3
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	103.0	100
DOUBS BEDINGTON	Mount Storm - Doubs	500	2598	100.6	
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	115.3	118.3
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	121.4	116.3
LOUDOUN MORRISVILLE	Mount Storm - Doubs	500	2598	94.3	
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	120.8	115.3
CUNNINGHAM-ELMONT & ELMONT TX	Mount Storm - Doubs	500	2598	100.5	98.7
DOOMS CUNNINGHAM	Mount Storm - Doubs	500	2598	95.0	
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	114.9	122.8
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	95.4	94.5
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	98.8	97.6
BATH VALLEY	Lexington - Dooms	500	2598	100.1	
DOOMS CUNNINGHAM	Endless Caverns 230-115 kV Tx	230	282.4	98.5	
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	131.4	129
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	130.7	129.2
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	109.4	
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	165.0	161
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	163.6	159.7
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	124.1	
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	103.9	

(105) As expected, the projected contingency overloads get worse in 2016. Specifically, both the BW and DVP contingency analyses show major reliability violations on the Mt. Storm–Doubs 500 kV

[24] The name of the power flow case is *S2016_02-22-07nolinev29.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of DVP list of expected contingency overloads is Attachment I.B.4.

line due to the loss of various 500 kV transmission lines.[25] The projected overloads on the Mt. Storm–Doubs line range between 94% and 121% (BW) and between 99% and 123% (DVP).

(106) Both the BW and DVP contingency analyses show that there is an even stronger need to improve the existing grid in order to reliably meet the expected load growth in 2016.

IV.3.3. No Loudoun Line without Possum Point Unit # 5 in 2011

(107) Exhibit 12 compares the BW and DVP lists of expected major contingency overloads in 2011 if the proposed Loudoun Line is not built and DVP's 736 MW Possum Point Unit #5 is also unavailable (i.e., the "stressed" condition).[26]

Exhibit 12: List of expected major contingency overloads in 2011 if the proposed Loudoun Line is not built and DVP's 736 MW Possum Point Unit #5 is also unavailable

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.4	95
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.1	94.5
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.9	105.4
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.4	105.2
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.7	108.3
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	107.6
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.6	93.4
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	94.7
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	93.8
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.7	114.5
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.6	119.2
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.4	
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	96.2	
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	148.2	149.7
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	144.1	146.8
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	113.7	

(108) Both the BW and DVP contingency analyses show major reliability violations on the Mt. Storm–Doubs 500 kV line due to the loss of the various 500 kV transmission lines. The projected

[25] In the 2011 case, both DVP and BW performed full AC load flow analysis. In the 2016 case, both DVP and BW performed DC load flow analysis.

[26] The name of the power flow case is *S2011_2007Forecastv29nlinenppt5v29.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of the DVP list of expected contingency overloads is Attachment I.B.5.

overloads on the Mt. Storm–Doubs line range between 96% and 112% (BW) and 93% and 108% (DVP).

(109) Therefore, both the BW and DVP contingency analyses show that there is a need to improve the existing grid in order to reliably meet expected load in 2011.

IV.3.4. No Loudoun Line without Possum Point Unit # 5 in 2016

(110) Exhibit 13 compares the BW and DVP lists of expected major contingency overloads in 2016 if the proposed Loudoun Line is not built and DVP's 736 MW Possum Point Unit #5 is unavailable.[27]

Exhibit 13: List of expected major contingency overloads in 2016 if the proposed Loudoun Line is not built and DVP's 736 MW Possum Point Unit #5 is unavailable

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	114.1	116
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	113.6	97.5
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	126.2	128.9
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	125.6	134.6
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	119.8	129
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	119.3	135.2
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	106.5	105.2
DOUBS BEDINGTON	Mount Storm - Doubs	500	2598	104.0	
CUNNINGHAM-ELMONT & ELMONT TX	Mount Storm - Doubs	500	2598	103.7	115.8
DOOMS CUNNINGHAM	Mount Storm - Doubs	500	2598	98.1	
LOUDOUN MORRISVILLE	Mount Storm - Doubs	500	2598	97.1	
LADYSMITH POSSUM PT	Mount Storm - Doubs	500	2598	94.2	
BRISTERS OX	Mount Storm - Doubs	500	2598	94.1	
GREENLANDGAP MEADOWBROOK	Cunningham - Elmont	500	2598	97.0	
MT STORM GREENLANDGAP	Cunningham - Elmont	500	2598	96.8	115.8
MT STORM DOUBS	Cunningham - Elmont	500	2598	95.2	98.5
BLACK OAK-HATFIELD & BLACK OAK TX	Cunningham - Elmont	500	2598		111.4
BEDINGTON BLACK_OAK	Cunningham - Elmont	500	2598		117.9
BRISTERS OX	Morrisville - Loudoun	500	2598	98.4	105.8
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598	95.9	
BLACK OAK-HATFIELD & BLACK OAK TX	Morrisville - Loudoun	500	2598		101.6
BEDINGTON BLACK_OAK	Morrisville - Loudoun	500	2598		117

[27] The name of the power flow case is *S2016_02-22-07nolinenppt5v29.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of the DVP list of expected contingency overloads is Attachment I.B.5. As noted, both DVP and BW used DC power flow in calculating expected contingency overloads in 2016.

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	102.1	99.8
LADYSMITH POSSUM PT	Bristers - Ox	500	2598	94.8	
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	103.8	104.6
BATH VALLEY	Lexington - Dooms	500	2598	105.9	
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	135.5	96.3
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	134.8	96.3
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	113.2	
DOOMS CUNNINGHAM	Endless Caverns 230-115 kV Tx	230	282.4	102.2	
BLACK OAK-HATFIELD & BLACK OAK TX	Endless Caverns 230-115 kV Tx	230	282.4	95.4	
BEDINGTON BLACK_OAK	Endless Caverns 230-115 kV Tx	230	282.4	95.2	
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	172.3	175.6
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	171.0	186.8
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	130.8	
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	110.6	
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Jackson - Edinburg	115	152	97.0	
BEDINGTON BLACK_OAK	Mount Jackson - Edinburg	115	152	96.7	

(111) As expected, the projected contingency overloads get worse in 2016. Both the BW and DVP contingency analyses show major reliability violations on the Mt. Storm–Doubs 500 kV line due to the loss of various 500 kV transmission line.[28] The projected overloads on the Mt. Storm–Doubs line range between 94% and 126% (BW) and 105% and 135% (DVP).

(112) Both the BW and DVP contingency analyses show that there is an even stronger need (compared to 2011 case) to improve the existing grid in order to reliably meet expected load in 2016 if Possum Point Unit # 5 is unavailable.

IV.3.5. Loudoun Line with Possum Point #5 in 2011

(113) If the proposed Loudoun Line is built in 2011, there is no projected reliability violation in 2011 in either the BW or the DVP analysis. The reason is that the proposed Loudoun Line carries a substantial amount of the west-to-east power flows, and this reduces the resulting power flows through the Mt. Storm–Doubs line.

(114) Specifically, without the proposed Loudoun Line, the existing Black Oak–Bedington, Mt. Storm–Doubs, and Mt. Storm–Greenland Gap 500 kV lines are expected to carry 2,240 MW, 2,011 MW,

[28] In 2011 case, both DVP and BW performed full AC load flow analysis. In 2016 case, both DVP and BW performed DC load flow analysis.

and 1,931 MW, respectively. With the proposed line, power flows on these lines are expected to be reduced to 1,948 MW, 1,830 MW, and 1,491 MW, respectively, because the proposed Mt. Storm to Meadowbrook 500 kV line is expected to carry 1,735 MW of power flow. Exhibit 14 summarizes the power flow reductions on existing 500 kV lines as a consequence of a new proposed Loudoun Line (with Possum Point #5 on).[29]

Exhibit 14: Power flow reductions on existing 500 kV lines as a consequence of a new proposed Loudoun Line in 2011 (with Possum Point #5 on)

Existing 500 kV Lines	Without Proposed Loudoun Line (MW)	With Proposed Loudoun Line (MW)	Reduction (%)
Conmaugh - Hunterstown	1,440	1,321	8
Black Oak - Bedington	2,240	1,948	13
Mt. Storm - Doubs	2,011	1,830	9
Mt. Storm – Greenland Gap	1,931	1,491	23
Dooms - Cunningham	1,009	851	16

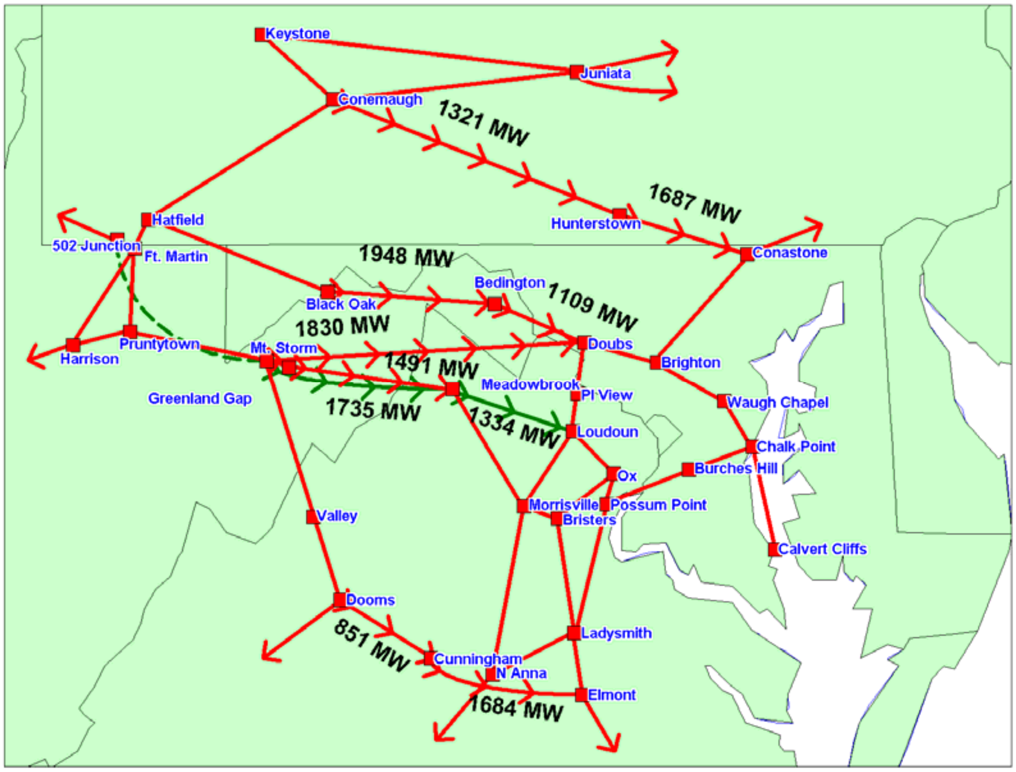
(115) The reduction ranges from 8% on the Conmaugh–Hunterstown line to as much as 23% on the Mt. Storm–Greenland Gap line as a consequence of the introduction of a new proposed Loudoun Line.[30] In addition, Dooms–Cunningham power flows in southern Virginia are reduced by 16% as a consequence of the introduction of a new proposed Loudoun Line, because a new Loudoun line—if built—carries an extra 1,735 MW of west-to-east power flows and, thereby, reduces the resulting power flows through the Mt. Storm–Valley–Dooms path that runs from West Virginia to southern Virginia.

(116) Exhibit 15 shows the expected power flows in 2011 if the proposed Loudoun Line is built.

[29] The name of the power flow case is *S2011_forecast_2007_v1v29pref.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of DVP list of expected contingency overloads is Attachment I.B.6.

[30] The reduction on power flows is highest in Mt. Storm–Greenland Gap, because the proposed Loudoun Line runs parallel to Mt. Storm–Greenland Gap to provide a redundant path to the west-to-east power transfers.

Exhibit 15: Expected power flows in 2011 if the proposed Loudoun Line is built



IV.3.6. Loudoun Line with Possum Point #5 in 2016

(117) Exhibit 16 compares the BW and DVP list of expected major contingency overloads in 2016 if the proposed Loudoun Line is on-line. Similar to the other 2016 cases described above, this case assumes that proposed Amos–Kemptown Line (A-K Line) and many other RTEP transmission improvements that are expected to be in service after 2011 but before 2016 would not be built by 2016.[31]

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31 The name of the power flow case is *S2016_02-22-07nolinev29pref.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of the DVP list of expected contingency overloads is Attachment I.B.6. As noted above, both DVP and BW used DC power flow in calculating expected contingency overloads in 2016.

Exhibit 16: List of expected major contingency overloads in 2016 if the proposed Loudoun Line is built

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	101.9	98.7
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	102.2	98.8
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	99.5	97.1
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	106.6	101.8

(118) Compared to the No Loudoun Line case, if the proposed Loudoun Line is built, there is a substantial reduction in contingency overloads in 2016 in both the BW and the DVP analyses. The proposed Loudoun Line carries a substantial amount of the west-to-east power flows and thus reduces resulting power flows through, *inter alia*, the Mt. Storm–Doubs line. For example, without the proposed Loudoun Line, contingency overloads on the Mt. Storm–Doubs 500 kV line (with a loss of the Greenland Gap–Meadowbrook line) are expected to be over 120% in 2016. With the proposed line, this particular contingency overload disappears.

(119) Even if the proposed Loudoun Line is built, expected contingency overloads remain on the Mt. Storm–Doubs 500 kV line (with a loss of either the Black Oak–Bedington or Hatfield–Black Oak 500 kV lines in 2016). However, these contingency overloads are expected to be reduced through ongoing PJM RTEP transmission expansion planning, such as the proposed Amos–Kemptown 765 kV line that is scheduled to be on-line in 2012. The remaining contingency overloads in lower voltage lines (such as the Endless Caverns 230–115 kV transformer and the Mt. Jackson–Edinburg 115 kV line) can be resolved by minor transmission upgrades such as additional transformers and upgrading of relevant lines. In fact, PJM RTEP shows numerous examples of such upgrades to resolve minor contingency overloads without building a major 500 kV line.

IV.3.7. Loudoun Line without Possum Point Unit # 5 in 2011

(120) Exhibit 17 compares the BW and DVP lists of expected major contingency overloads in 2011 if the proposed Loudoun Line is built, but DVP's Possum Point #5 is unavailable (i.e., the "stressed" condition).[32]

[32] The name of the power flow case is *s2011_forecast_2007_v1v29prefnppt5.raw*." It was provided by DVP in response to Staff Data Request 2-12. The source of DVP list of expected contingency overloads is Attachment I.B.7.

Exhibit 17: List of expected major contingency overloads in 2011 if the proposed Loudoun Line is built (the "stressed" condition)

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson – Edinburg	115	152	98.4	98.6

(121) If the proposed Loudoun Line is built in 2011, there are no projected major reliability violations in 2011 in either the BW or the DVP analysis. The proposed Loudoun Line would carry a substantial amount of the west-to-east power flows; reducing power flows through the Mt. Storm–Doubs line.[33]

(122) Specifically, without the proposed Loudoun Line, the existing Black Oak–Bedington, Mt. Storm–Doubs, and Mt. Storm–Greenland Gap 500 kV lines are expected in 2011 to carry 2,267 MW, 2,060 MW, and 1,970 MW, respectively, if 736 MW Possum Point #5 is unavailable. With the proposed Loudoun Line, power flows on these lines are expected to be reduced in 2011 to 1,972 MW, 1,875 MW, and 1,529 MW, respectively, because the proposed Mt. Storm to Meadowbrook 500 kV line is expected to carry 1,777 MW of power flow.

(123) Exhibit 18 summarizes the power flow reductions on existing 500 kV lines as a consequence of a new proposed Loudoun Line in 2011 (with Possum Point #5 off).

Exhibit 18: Power flow reductions on existing 500 kV lines as a consequence of a new proposed Loudoun Line in 2011 (with Possum Point #5 off)

Existing 500 kV Lines	Without Proposed Loudoun Line (MW)	With Proposed Loudoun Line (MW)	Reduction (%)
Conmaugh - Hunterstown	1,472	1,335	9
Black Oak – Bedington	2,267	1,972	13
Mt. Storm - Doubs	2,060	1,875	9
Mt. Storm – Greenland Gap	1,970	1,529	22
Dooms - Cunningham	1,025	857	16

(124) The reduction ranges from 9% on the Conmaugh–Hunterstown and Mt. Storm–Doubs lines to as much as 22% on the Mt. Storm–Greenland Gap line as a consequence of introduction of the Loudoun Line.[34] In addition, the Dooms–Cunningham power flows in southern Virginia are also reduced by 16% as a consequence of the introduction of the Loudoun Line, because a new

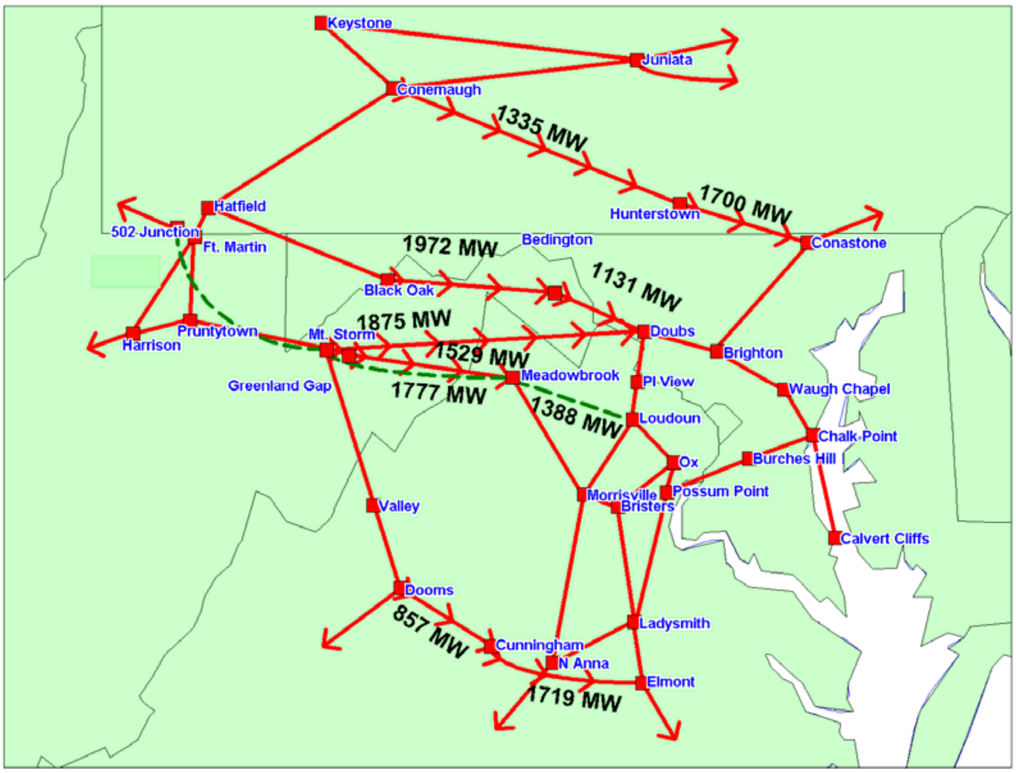
33 As noted earlier, minor transmission overloads on the Mt. Jackson–Edinburg 115 kV line can be resolved by conventional measures that do not require major transmission expansion planning.

34 The reduction in power flows is highest in Mt. Storm–Greenland Gap because the proposed Loudoun Line runs parallel to Mt. Storm-Greenland Gap to provide a redundant path to the west-to-east power transfers.

Loudoun line—if built—carries an extra 1,777 MW of west-to-east power flows and thereby reduces the resulting power flows through the Mt. Storm–Valley–Dooms path that runs from West Virginia to southern Virginia.

(125) Exhibit 19 shows the expected power flows in 2011 if the proposed Loudoun Line is built and DVP's 736 MW Possum Point #5 is unavailable.

Exhibit 19: Expected power flows in 2011 if the proposed Loudoun Line is built and DVP's 736 MW Possum Point #5 is unavailable



IV.3.8. Loudoun Line without Possum Point Unit # 5 in 2016

(126) Exhibit 20 compares the BW and DVP lists of expected major contingency overloads in 2016 if the proposed Loudoun Line is on-line but the 736 MW Possum Point Unit #5 is unavailable. This case also assumes that the proposed Amos–Kemptown Line (A-K Line) and many other RTEP transmission improvements that are expected to be in service after 2011 but before 2016 would not be built by 2016.[35]

[35] The name of the power flow case is *S2016_02-22-07nolinev29prefnppt5.raw*. It was provided by DVP in response to Staff Data Request 2-12. The source of DVP list of expected contingency overloads is Attachment I.B.7. As noted above, both DVP and BW used DC power flow in calculating expected contingency overloads in 2016.

Exhibit 20: List of expected major contingency overloads in 2016 if the proposed Loudoun Line is built (No Possum Point #5 case)

Contingency	Overload	kV	Rating (MVA)	BW (%)	DVP (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.7	106.5
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	105.3	109.8
BATH VALLEY	Lexington - Dooms	500	2598	99.1	
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	103.1	100.5
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	112.8	108.7

(127) Compared to the No Loudoun Line case, if the proposed Loudoun Line is built, there is a substantial reduction in contingency overloads in 2016 in both the BW and the DVP analyses, even though 736 MW Possum Point Unit #5 is out of service. The reason is that the proposed Loudoun Line carries a substantial amount of the west-to-east power flows, and this reduces the resulting power flows through, inter alia, the Mt. Storm–Doubs line. Specifically, without the proposed Loudoun Line, contingency overloads on the Mt. Storm–Doubs 500 kV line (with the loss of the Greenland Gap–Meadowbrook line) are expected to be over 125% in 2016. With the proposed line, this particular contingency overload disappears.

(128) Note that even if the proposed Loudoun Line is built, expected contingency overloads remain on the Mt. Storm–Doubs 500 kV line (with a loss of either the Black Oak–Bedington or Hatfield–Black Oak 500 kV lines in 2016). However, these contingency overloads are expected to be reduced by ongoing PJM RTEP transmission expansion planning such as the proposed Amos–Kemptown 765 kV line, which is scheduled to be on-line in 2012. The remaining contingency overloads in lower voltage lines (such as the Endless Caverns 230–115 kV transformer and the Mt. Jackson–Edinburg 115 kV line) can be resolved by minor transmission upgrades such as additional transformers and the upgrading of relevant lines. In fact, PJM RTEP shows numerous examples of such upgrades to resolve minor contingency overloads without building a major 500 kV line.

(129) In summary, Bates White has conducted an independent study to verify DVP's own analysis and to determine the need for the proposed Loudoun Line. The results of Bates White's study verify DVP's own reliability study results: i.e., without additional system improvements, the existing system will experience reliability violations on major 500 kV lines that are critical to reliably meeting the expected demand growth in the PJM mid-Atlantic region and the northern Virginia area. Bates White also finds that, based on the information available to the Applicants' at the time of their needs assessment, the proposed Loudoun Line is an adequate solution to resolve the

expected reliability violations that may occur as early as 2011. The next chapter summarizes the alternative solutions studied by Bates White and compares the merits of those alternatives to those of the proposed Loudoun Line solution.

V. Alternatives studied

(130) In the previous chapter, Bates White independently verified the need for system expansion to reliably meet the growing demand of the mid-Atlantic region and northern Virginia. Bates White concluded that the proposed Loudoun Line could serve as a feasible solution to resolve major contingency overloads expected to occur as early as 2011. In this chapter, Bates White evaluates the feasible alternatives that may also resolve major contingency overloads expected to occur as early as 2011.

(131) The two alternatives that Bates White considers *feasible* are:

- Building the 502 Junction–Mt. Storm–Meadowbrook–Doubs 500 kV line (“Doubs Option”)
- Replacing the 500 kV Meadowbrook–Loudoun segment of the proposed line with a 230 kV double-circuit line, in concert with the assumption that three Sempra units with a total capacity of 640 MW near Doubs will be on-line by 2011 (“Two 230 kV plus Sempra Option”)

(132) Alternatives that Bates White examined but considers *more uncertain are*:

- Building the Amos–Kemptown 765 kV line (“A-K Option”); the earliest in-service date of AEP’s A-K line is 2012, and thus it cannot resolve the expected 2011 reliability violations
- Installing AC power flow controllers in concert with the assumption that additional generation will come on-line in strategic locations

(133) Alternatives that Bates White finds *not feasible* are:

- Terminating the proposed line at the Meadowbrook substation (“No Loudoun Segment Option”)
- Adding over 5,000 MW of generation in Virginia and Maryland
- Reducing more than 5,000 MW of demand in the Dominion zone, or over 3,500 MW in the northern Virginia area.

(134) While certain alternatives may be technically feasible, not all of them represent the same level of risk in terms of fruition. Some, such as the Amos–Kemptown line, rely on future transmission projects that, while approved by PJM, will be subject to siting and regulatory uncertainties that are similar to, if not greater than, those faced by the presently proposed line, depending on the need for Greenfield corridors and/or the need to cross existing conservation easements. The Meadowbrook–Doubs transmission line alternative would, in addition to the previously described siting risk, increase the reliance on Doubs (which is located in Maryland) as the source for even more power to flow into northern Virginia, and thus further aggravate the critical reliance of northern Virginia on outside resources to reliably meet its expected demand growth. Alternatives involving facilities located outside of Virginia are beyond the Commission's jurisdiction, and therefore outside of the Commission's direct control.

(135) The following sections report on transmission, generation, and demand response alternatives (and combinations thereof) that Bates White has studied.

V.1. Transmission alternatives

(136) Bates White has studied the following transmission alternatives:

- No Loudoun Segment Option. This option terminates the proposed line at the Meadowbrook substation instead of the Loudoun substation
- Doubs Option. This option changes the terminal substation of the proposed line from the Loudoun substation to the Doubs substation
- Two 230 kV Option. This option builds a double-circuit 230 kV line on the Meadowbrook–Loudoun segment of the proposed Loudoun line instead of a single 500 kV line
- Amos–Kemptown Option. This option relies on the Amos–Kemptown 765 kV line to resolve the near-term reliability violations expected to occur as early as 2011
- FACTS Option. Bates White implemented a FACTS option by installing a PAR either on the Mount Storm–Doubs line or on the Pruntytown–Mount Storm line.

(137) The following subsections describe the results and comparative merits of above-listed transmission alternatives in detail.

V.1.1. No Loudoun segment option

(138) Bates White considered the alternative of building a new 500 kV line that starts from 502 Junction in Pennsylvania, extends to Mt. Storm in West Virginia, and ends at AP's Meadowbrook

substation in Frederick County, Virginia. This alternative is equivalent to not building the Meadowbrook-to-Loudoun section of the proposed Loudoun Line. This alternative does not resolve major contingency overloads expected to occur in 2011 and, thereby, is not a feasible alternative.

(139) Exhibit 21 shows the NERC N-1 Contingency Reliability Study results for this alternative that show expected major contingency overloads in 2011 with and without 736 MW Possum Point #5.

Exhibit 21: NERC N-1 Contingency Reliability Study results for a transmission alternative of not building the Meadowbrook–Loudoun section of the proposed line

Contingency	Overload	kV	Rating (MVA)	PPT5 On (%)	PPT5 Off (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	102.96	104.57
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	101.58	103.99
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	100.39	103.17
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	95.89	103.98
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	104.31	110.67
BRISTERS OX	Morrisville - Loudoun	500	2598	94.92	101.69
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598	94.89	100.73
MT STORM DOUBS	Morrisville - Meadowbrook	500	2598		94.13

(140) Compared to not building the entire proposed Loudoun Line, this transmission alternative resolves major contingency overloads on the Pruntytown–Mt. Storm 500 kV line in 2011. However, this alternative does not resolve the Mt. Storm-Doubs contingency overloads. It ranges between 100% and 103% with Possum Point Unit # 5. Without Possum Point Unit # 5, it ranges between 103% and 105%. .Most notably, this alternative will make contingency overloads *worse* on existing 500 kV lines that are located to the west and south of the Meadowbrook substation. This occurs because extra west-to-east power transfer through a new Mt. Storm–Meadowbrook path increases power flows on the existing 500 kV lines east and south of Meadowbrook substation.

(141) Exhibit 22 summarizes the NERC N-1 Contingency Reliability Study results for this alternative compared to not building the entire Loudoun Line for the 500 kV lines west and south of the Meadowbrook substation (2011 No Possum Point Unit # 5 case).

Exhibit 22: NERC N-1 Contingency Reliability Study results for this alternative compared to not building the entire Loudoun Line for 500 kV lines west and south side of Meadowbrook substation (2011 No Possum Point Unit # 5 case)

Contingency	Overload	kV	Rating (MVA)	No Loudoun Line (%)	No Loudoun Segment (%)
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	104.0
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	110.7
BRISTERS OX	Morrisville - Loudoun	500	2598		101.7
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598		100.7
MT STORM DOUBS	Morrisville - Meadowbrook	500	2598		94.1

(142) Contingency overloads on Bristers–Ox and Morrisville–Bristers 500 kV lines increase to 104% and 110%, respectively, for this alternative compared to the contingency overloads of 96% and 98%, respectively, for not building the proposed Loudoun Line. Moreover, there are new contingency overloads on the Morrisville–Loudoun and Morrisville–Meadowbrook 500 kV lines that are not expected to occur if the Loudoun Line is not built. As described above, the additional west-to-east power transfer through a new Mt. Storm–Meadowbrook line increases flows on lines east and south of the Meadowbrook substation. If the Loudoun Line is not built, such extra power transfer does not exist to overload lines east and south of the Meadowbrook substation.

(143) The contingency overloads get worse in 2016. Exhibit 23 shows the NERC N-1 Contingency Reliability Study results for this alternative and the expected major contingency overloads in 2016 with and without 736 MW Possum Point #5.[36]

[36] As explained above, both analyses were conducted using DC load flow, and the A-K line is assumed not to be built by 2016.

Exhibit 23: NERC N-1 Contingency Reliability Study results in 2016 for a transmission alternative of not building the Meadowbrook–Loudoun section of the proposed line

Contingency	Overload	kV	Rating (MVA)	With PPT5 Loading (%)	No PPT5 Loading (%)
LADYSMITH POSSUM PT	Mount Storm - Doubs	500	2598		97.0
LOUDOUN MORRISVILLE	Mount Storm - Doubs	500	2598	97.7	101.0
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	116.2	120.6
LADYSMITH ELMONT	Mount Storm - Doubs	500	2598		95.4
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	96.6	100.0
DOUBS BEDINGTON	Mount Storm - Doubs	500	2598	102.3	106.2
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	112.5	117.0
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	96.4	99.7
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	115.8	120.2
DOOMS CUNNINGHAM	Mount Storm - Doubs	500	2598	95.9	99.5
BRISTERS OX	Mount Storm - Doubs	500	2598	94.1	97.4
BRISTERS MORRISVILLE	Mount Storm - Doubs	500	2598		96.0
BATH LEXINGTON	Mount Storm - Doubs	500	2598		94.0
DOOMS VALLEY	Mount Storm - Doubs	500	2598		95.5
CUNNINGHAM-ELMONT & ELMONT TX	Mount Storm - Doubs	500	2598	100.5	104.2
CLIFTON-OX & CLIFTON TX #2	Mount Storm - Doubs	500	2598		94.0
LADYSMITH POSSUM PT	Bristers - Ox	500	2598		100.8
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	104.1	111.1
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	112.8	118.3
BATH VALLEY	Dooms - Lexington	500	2598		98.8
MORRISVILLE MEADOWBROOK	Cunningham - Elmont	500	2598		94.9
BRISTERS OX	Morrisville - Loudoun	500	2598	103.0	108.2
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598	103.3	107.9
MT STORM DOUBS	Morrisville - Loudoun	500	2598		96.5
CUNNINGHAM-ELMONT & ELMONT TX	Morrisville - Meadowbrook	500	2598		98.7
MT STORM DOUBS	Morrisville - Meadowbrook	500	2598		109.0
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4		96.4
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152		100.6

(144) As expected, the numbers and severities of reliability violations increase in 2016. For example, the number of contingency overloads in the Mt. Storm–Doubs line increases from three to sixteen between 2011 and 2016. Moreover, contingency overloads on the Mt. Storm–Doubs line (with the loss of the Black Oak–Bedington line) increase from 104% to 120% between 2011 and

2016.Therefore, not building a Meadowbrook to Loudoun Section of the proposed Loudoun Line is not a feasible alternative in 2011 and 2016.

(145) Exhibit 24 and Exhibit 25 show total and differential (compared to no Loudoun Line case) power flows on various 500 kV transmission lines if the Meadowbrook–Loudoun section of the proposed line is not built.

Exhibit 24: Total power flows: no Meadowbrook–Loudoun section (2011, no Possum Point Unit #5)

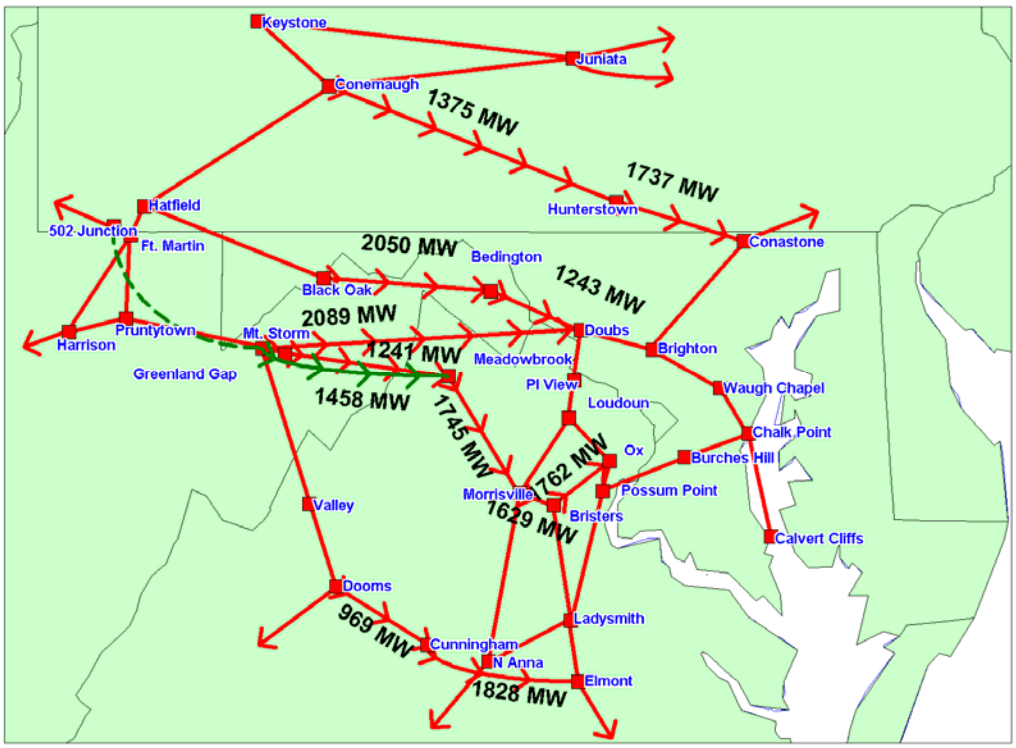
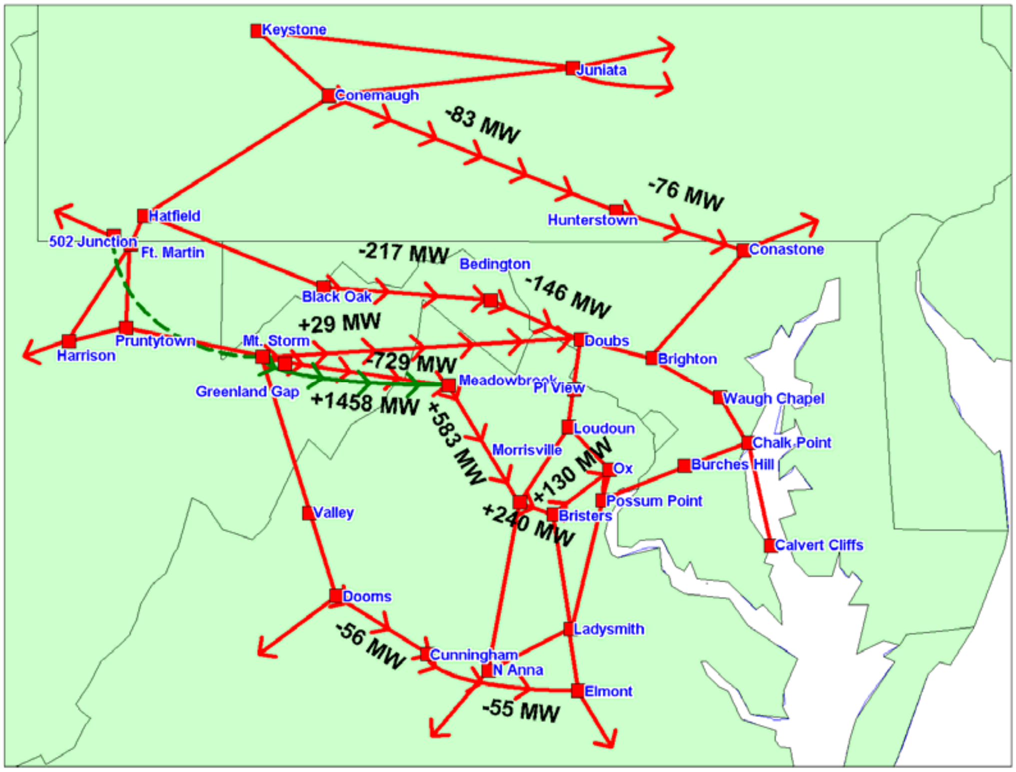


Exhibit 25: Differential power flows: no Meadowbrook–Loudoun segment versus no Loudoun Line case (2011, no Possum Point Unit #5)



V.1.2. Doubs option

(146) A feasible transmission alternative that Bates White studied is to change the terminal substation from Loudoun in Virginia to Doubs in Maryland. As shown in Exhibit 26, this is a feasible transmission alternative in 2011.[37] The KEMA Report also concludes that this transmission alternative is a feasible solution to resolve the major contingency overloads expected to occur in 2011.[38]

Exhibit 26: NERC N-1 Contingency Analysis results for 502 Junction–Mt. Storm–Meadowbrook–Doubs 500 kV Line case in 2011

Contingency	Overload	kV	Rating (MVA)	With PPT5 Loading (%)	No PPT5 Loading (%)
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152		99.37

[37] Minor transmission overloads in the Mount Jackson–Edinburg 115 kV line can be fixed with other conventional network upgrades.

[38] KEMA Report, at 49.

(147) In 2016, both KEMA and DVP conclude that this alternative does not meet the need.[39] However, Bates White's study shows that this transmission alternative meets the reliability need better than the DVP's proposed Loudoun Line solution in 2016 in terms of reducing the expected contingency overloads on the major 500 kV transmission lines. Exhibit 27 compares the proposed Loudoun Line option and the Doubs option with respect to the list of projected major contingency overloads in 2016 if the 736 MW Possum Point Unit #5 is unavailable. Both studies assume that the proposed Amos–Kemptown Line (A-K Line) is not built by 2016.[40]

Exhibit 27: Comparison of projected major contingency overloads in 2016 between Loudoun Line option and the Doubs option (No Possum Point #5 case)

Contingency	Overload	kV	Rating (MVA)	Loudoun Line Option (%)	Meadowbrook – Doubs (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.7	
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	105.3	
BATH VALLEY	Lexington - Dooms	500	2598	99.1	99.7
LOUDOUN - MORRISVILLE	Morrisville - Bristers	500	2598		94.9
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	103.1	103.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	112.8	113.7
DOOMS - CUNNINGHAM	Mount Jackson - Edinburg	115	152		94.5

(148) In 2016, the Doubs Option better meets the reliability need than the proposed Loudoun Line in terms of reducing the expected contingency overloads on the major 500 kV transmission lines. Specifically, there are no remaining expected contingency overloads on the Mt. Storm–Doubs 500 kV line (with a loss of either the Black Oak–Bedington or the Hatfield–Black Oak 500 kV line). The reason is that the Meadowbrook–Doubs alternative runs more parallel to the overloaded Mt. Storm–Doubs line than the DVP-proposed Loudoun Line solution. As shown in Exhibit 28, this conclusion does not change even with full AC power flow contingency analysis.

[39] Id., and Appendix, at 52.

[40] DC load flow analysis was used for the 2016 case.

Exhibit 28: Comparison of projected major contingency overloads in 2016 (No Possum Point #5 case) between the proposed Loudoun Line and the Doubs option (full AC power flow results)

Contingency	Overload	kV	Rating (MVA)	Loudoun Line Option (%)	Meadowbrook - Doubs (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	102.0	
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	94	96.1
BATH VALLEY	Dooms - Lexington	500	2598	98.7	99.3
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.1	101.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	108.1	109.0

(149) Due to significant uncertainties in forecasting the future in 2016, it would be premature to conclude that the Meadowbrook–Doubs option is better than the proposed Loudoun Line solution. In addition, many ongoing PJM RTEP transmission expansions (such as the proposed Amos–Kemptown 765 kV line scheduled to be on-line in 2012) and generation that have signed interconnection agreements after DVP filed the application are not included in this case study. Despite such uncertainty, Bates White concludes that this Meadowbrook– Doubs alternative (Doubs Option) is *as technically feasible as* the DVP proposed Loudoun Line in both 2011 and 2016.

(150) Exhibit 29 and Exhibit 30 show differential (compared to Loudoun Line option) power flows on various 500 kV transmission lines for the Meadowbrook–Doubs transmission alternative in 2011 and 2016, respectively.[41]

[41] Full AC power flow results are shown for 2011 and 2016.

Exhibit 29: Differential power flows in 2011—Doubs option versus Loudoun Line option (2011, no Possum Point Unit #5)

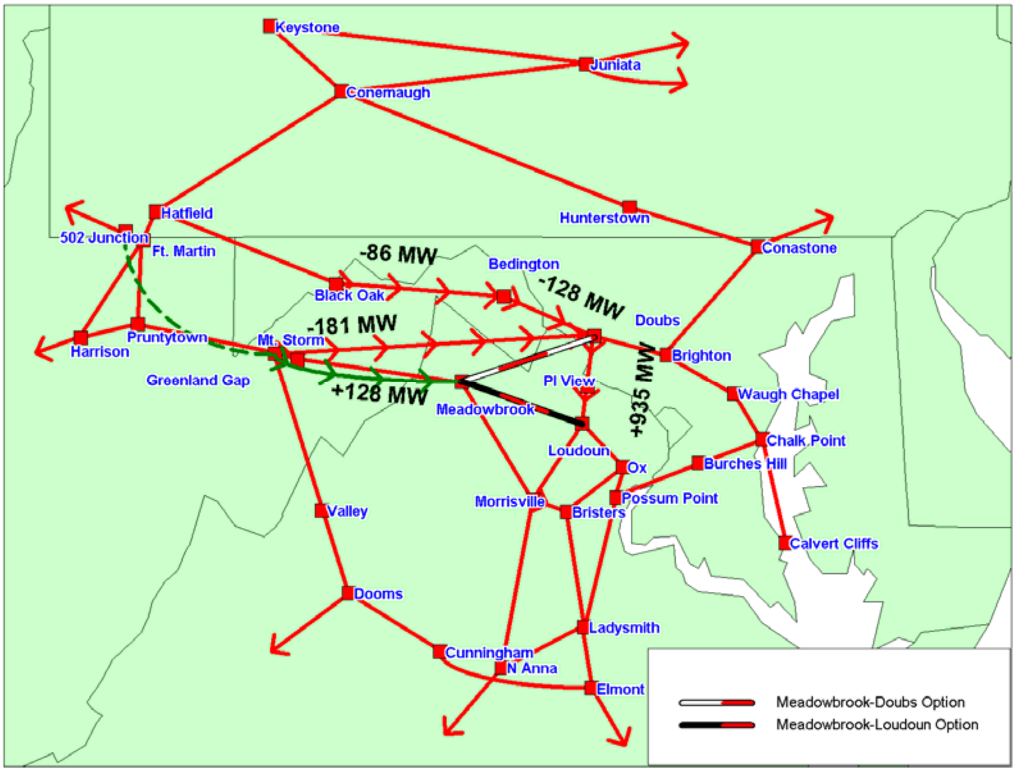
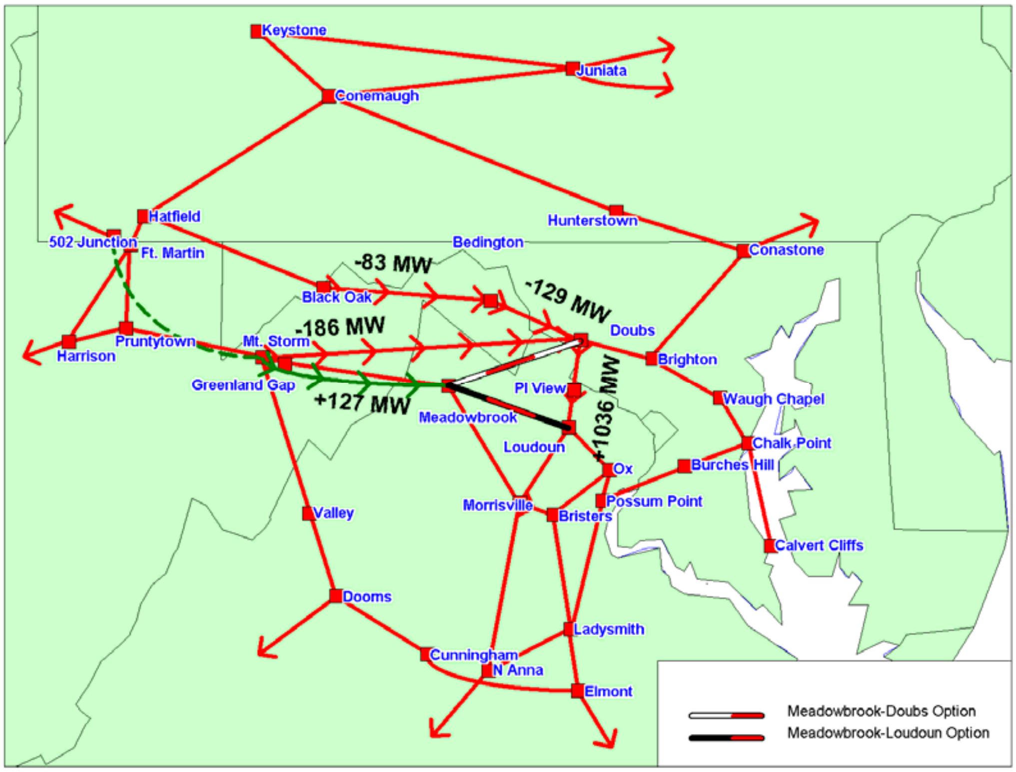


Exhibit 30: Differential power flows—Doubs option versus Loudoun Line option (2016, no Possum Point Unit #5)



(151) In 2011, the Meadowbrook–Doubs option creates 181 MW less flow on the Mt. Storm–Doubs line than the Meadowbrook–Loudoun option, because the Doubs option runs electrically more proximate and parallel to the Mt. Storm–Doubs line than the Loudoun option and, thus, reduces Mt. Storm–Doubs line loads. Similarly, the Doubs option creates 128 MW more flow on a new Mt. Storm–Meadowbrook line than the Loudoun option. In 2011, the Doubs option creates 935 MW more flow on the existing Doubs–Pl. View line (i.e., north-to-south path) than the Loudoun option, because northern Virginia would receive more power from the Doubs substation. The Doubs option does not provide a direct 500 kV path to northern Virginia.

(152) In 2016, the Meadowbrook–Doubs option creates 186 MW less flow on the Mt. Storm–Doubs line than the Meadowbrook–Loudoun option, because the Doubs option runs electrically more proximate and parallel to the Mt. Storm–Doubs line than the Loudoun option and, thus, reduces Mt. Storm–Doubs line loads. The Doubs option creates 127 MW more flow on a new Mt. Storm–Meadowbrook line than the Loudoun option. In 2011, the Doubs option creates 1,036 MW more flow on the existing Doubs– Pl. View line (i.e., north-to-south path) than the Loudoun option

V.1.3. Two 230 kV option

(153) This alternative examines the effect of building the Meadowbrook-to-Loudoun segment of the proposed Loudoun Line with double-circuit 230 kV lines instead of a single 500 kV line. This alternative requires additional network upgrades such as adding 500/230 kV transformers and a 230 kV switchyard at the Meadowbrook substation. Both KEMA and DVP conclude that this alternative is unacceptable by 2016.[42] However, neither KEMA nor DVP evaluated this option for 2011.[43] Therefore, it is important to evaluate this option for 2011 with and without Possum Point Unit # 5.

(154) Exhibit 31 shows NERC N-1 Contingency Analysis results for a transmission alternative of building the Meadowbrook-to-Loudoun segment of the proposed Loudoun Line with double-circuit 230 kV lines in 2011

Exhibit 31: NERC N-1 Contingency Analysis results for two 230 kV case in 2011

Contingency	Overload	kV	Rating (MVA)	With PPT5 Loading (%)	No PPT5 Loading (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	96.4	98.26
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	95.86	97.99
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598		94.71
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598		97.5
CUNNINGHAM-ELMONT & ELMONT TX	Mt Jackson - Edinburg	115	152		96.95

(155) This alternative does not fully resolve the reliability violations in 2011. For example, the Mt. Storm–Doubs line is expected to be loaded at 98% (with a loss of the Hatfield–Black Oak and Black Oak–Bedington line) when the Possum Point Unit # 5 unit is unavailable. By comparison, not building a proposed Loudoun Line could be expected to result in an overload of 106% on the same line, with the same contingency condition. Thus, this alternative will reduce the expected contingency loading on the Mt. Storm–Doubs line by 8%. As a consequence, in order to reliably serve needs in 2011, this alternative requires further support by way of expanding transmission, adding generation, and/or reducing demand.

(156) Exhibit 32 shows the differential (compared to the Loudoun Line option) power flows on various 500 kV transmission lines for the two 230 kV Meadowbrook–Loudoun double-circuit alternative in 2011 when the Possum Point Unit # 5 unit is unavailable.

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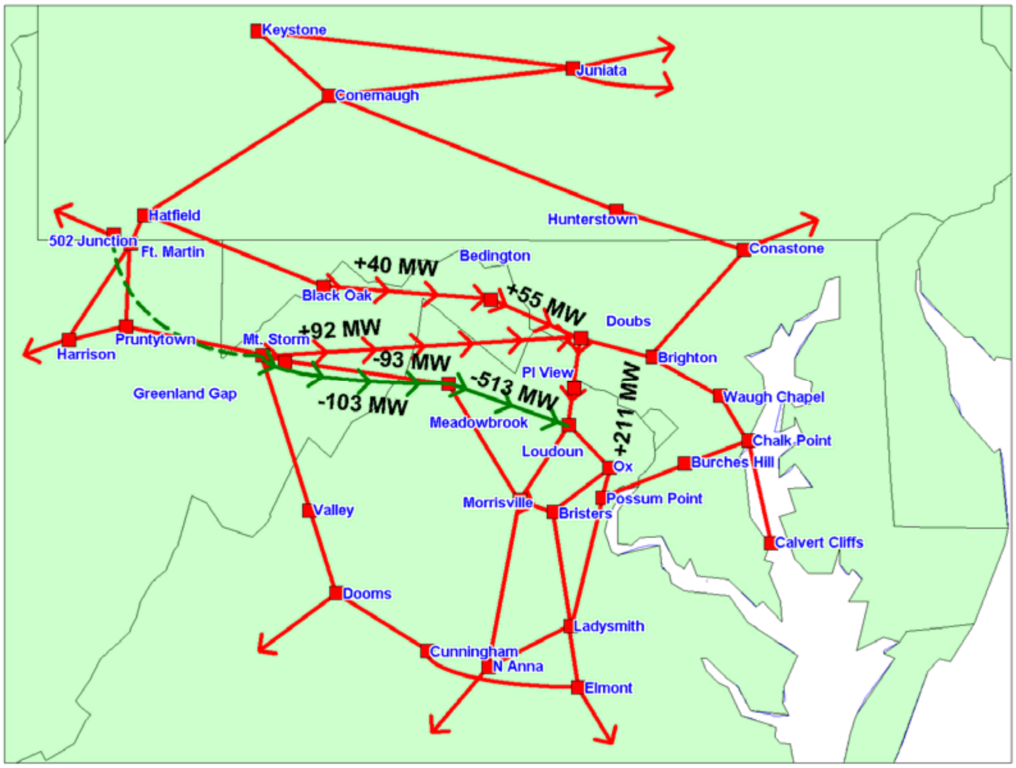
[42] KEMA Report, at 54; Appendix, at 53.

[43] Staff Set 2-12KEMA, *Read-me-for-Raw-Data-files.doc*.

Exhibit 32: Differential power flows—Two 230 kV option versus a single 500kV option (2011, no Possum Point Unit #5)



(157) Compared to a single 500 kV line option, a two 230 kV double-circuit line option increases the Mt. Storm–Doubs line loadings by 92 MW in 2011, when Possum Point Unit # 5 is unavailable. As a consequence, this alternative shows new contingency overloads on the Mt. Storm–Doubs line (with a loss of either a Hatfield–Black Oak or Black Oak–Bedington line). This increase in loading is compensated by a decrease in expected loading of a new Mt. Storm–Meadowbrook line by 103 MW. Overall, the total west-to-east power flow of this transmission alternative is about the same as the DVP-proposed Loudoun Line.

(158) The most notable difference between the two 230 kV option and the single 500 kV line on the Meadowbrook–Loudoun segment is the significantly reduced flow between the Meadowbrook–Loudoun path. Specifically, 1,388 MW of expected loading of that path is reduced to 875 MW if a single 500 kV line is replaced by two 230 kV double-circuit lines (i.e., a 513 MW reduction in flow as shown in Exhibit 32).

(159) Because of a significantly reduced flow on the Meadowbrook–Loudoun segment, this alternative does not sufficiently reduce the expected flows on other parallel lines such as Bristers–Ox and Morrisville–Bristers. As a consequence, this alternative shows new contingency overloads in such lines, with a loss of a Loudoun–Morrisville line. With this option, the northern Virginia load is expected to rely more on the north-to-south power flow as shown by the increase in Doubs to Pl. View flows by 211 MW in Exhibit 32.

V.1.3.1. Two 230 kV plus Sempra Option

(160) Bates White also studied the amount of additional generation needed to make this transmission alternative feasible in terms of meeting 2011 reliability needs. The outcome of this analysis is critically dependent on both the amount and the location of added generation. More details can be found in the Generation Alternatives section of this report.

(161) Specifically, Bates White added three Sempra units (640 MW total) near the Doubs Substation and conducted the NERC N-1 Contingency Analysis. Bates White chose three Sempra units because (a) they are already modeled in DVP base case but are turned off because they were in suspension at the time of DVP base case development; (b) they are out of suspension now and thus eligible for modeling; and (c) their location (i.e., Doubs) significantly reduces power flows on the Mt. Storm–Doubs line. Bates White's analysis shows that adding three Sempra units for a total 640 MW makes this transmission alternative feasible in 2011 even when the 736 MW Possum Point Unit # 5 is unavailable.[44]

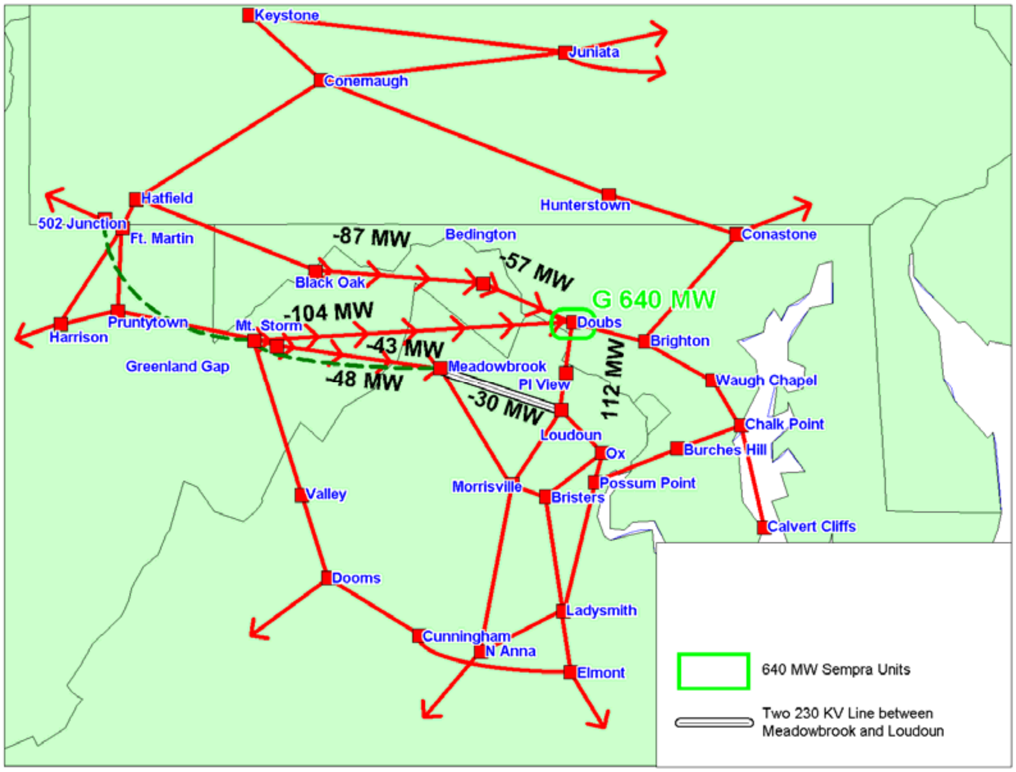
(162) However, based on current expectations of future system conditions, Bates White finds that this alternative is inferior to the proposed Loudoun Line option because this alternative carries significantly less power flow between Meadowbrook and Loudoun, and thus is less effective in preventing the contingency overloads on other lines after 2011.

(163) Exhibit 33 illustrates a two 230 kV option plus the Sempra units near Doubs as a feasible alternative to the proposed Loudoun Line. Exhibit 33 also shows the MW impact of adding 640 MW Sempra units on various 500 kV transmission lines. For example, adding 640 MW Sempra units reduces Mt. Storm–Doubs loading by 104 MW. By contrast, Doubs to Pl. View north-south flow is expected to increase by 112 MW, if 640 MW of new generation is added near Doubs. This

[44] Note that contingency loading of the Morrisville–Bristers line with a loss of the Loudoun–Morrisville line is 94.4%, slightly over 94% (a reliability violation threshold according to DVP planning criteria). Given that (a) Mt. Storm–Doubs contingency overload (not the Morrisville–Bristers) is a major issue in this case; (b) uncertainties associated with data inputs and modeling assumptions are larger than the difference between the 94.4% loading and the DVP's 94% threshold; and (c) 94.4% contingency loading occurs when Possum Point Unit #5 is unavailable (i.e., the "stressed" condition), we judged that they meet the reliability need in 2011.

increased north-to-south flow from Doubs subsequently decreases west-to-east flow on the Meadowbrook–Loudoun 230 kV double-circuit lines by 30 MW.

Exhibit 33: MW impact of adding 640 MW Sempra units near Doubs to the two 230 kV option (2011, no Possum Point Unit #5)

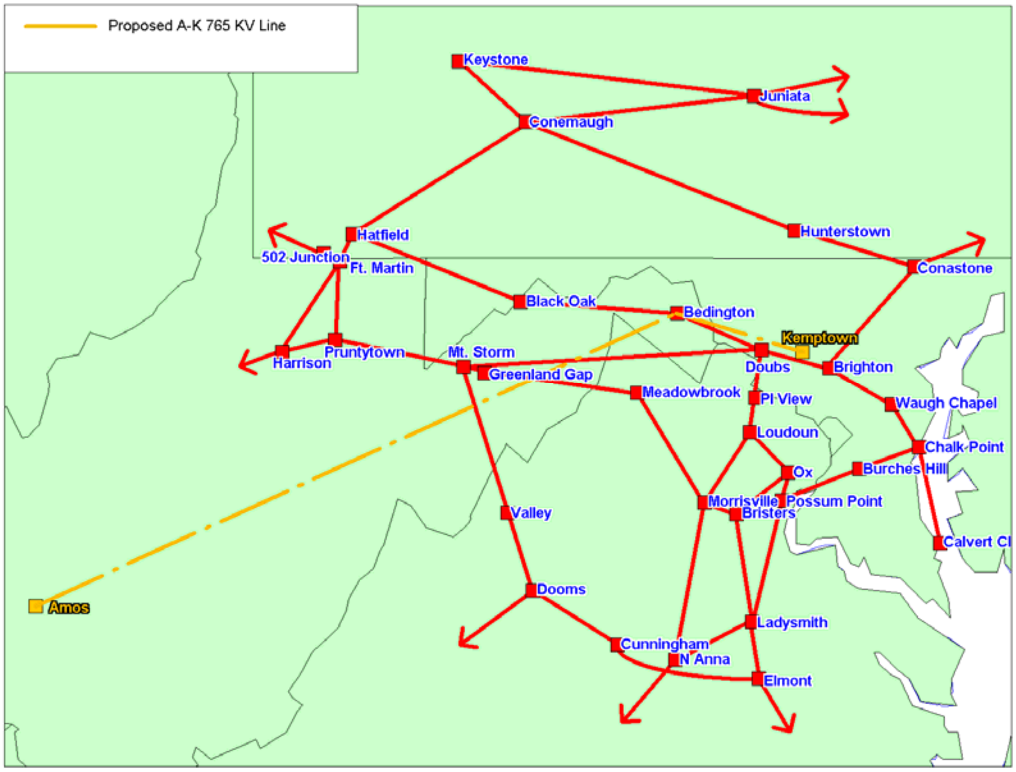


V.1.4. Amos – Kemptown option

(164) AEP and AP propose to build a new 765 kV line extending from the John Amos substation near St. Albans, West Virginia, to the Bedington substation. From the Bedington substation, a double-circuit 500 kV line will be extended to a new substation in Kemptown, Maryland, near the existing Doubs–Brighton and Brighton–Conastone 500 kV lines. The expected in-service date is June 1, 2012, and the expected cost is approximately $1.8 billion.

(165) Exhibit 34 illustrates a new proposed Amos–Kemptown 765 kV line (A-K 765 kV Line) and existing 500 kV transmission lines.

Exhibit 34: Proposed A-K 765 kV Line and existing 500 kV transmission system



(166) Since the expected in-service date of the proposed A-K 765 kV line is no earlier than 2012, this transmission alternative cannot resolve reliability violations expected to occur in 2011. In addition, this transmission alternative involves additional risks due to: (a) the uncertainty of its timely completion by 2012; and (b) the increased potential opposition to siting a line with all new rights of way. In spite of the caveats noted above, Bates White analyzed the impact of A-K Line as an alternative to the proposed Loudoun Line.

(167) The A-K Option alternative analysis is based on the PJM 2012 retool case.[45] This PJM retool case models year 2012 system condition. The ratings of the proposed Loudoun Line were modified to be consistent with the current understanding of the design characteristics of the proposed line.[46] Exhibit 35 shows the list of contingency overloads expected to occur in 2012 if neither the Loudoun Line nor the A-K Line is in service by 2012.[47]

45 The name of the power flow case used is *rtep2012_mtx_060107_retool.raw*.

46 Specifically, the DVP-owned Loudoun Segment of the proposed line was corrected to be 3,464 MVA for both normal and emergency rating and the rest of the line, owned by AP, was corrected to be 4,161 MVA and 5,269 MVA for normal and emergency rating, respectively.

47 When Possum Point Unit #5 is unavailable, two of the contingency conditions (i.e., loss of Hatfield–Black Oak

Exhibit 35: List of contingency overloads expected to occur in 2012 if neither Loudoun Line nor A-K Line is in service by 2012

Contingency	Overload	kV	Rating (MVA)	With PPT5 Loading (%)	No PPT5 Loading (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	102.6	103.9
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	102.3	103.5
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	107.6	114.1
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	105.8	113.7
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	113.2	115.8
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	113.9	116.6
DOUBS BEDINGTON	Mount Storm - Doubs	500	2598	94.2	96.2
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	101.1	104.4
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	100.0	103.4

(168) Compared to the 2011 contingency analysis results, expected 2012 contingency overloads get larger for both the Pruntytown–Mt. Storm and Mt. Storm–Doubs lines. Simply put, without major transmission expansion by 2012, reliability violations on the existing system become more severe.

(169) Bates White has also studied the impact of not building the Loudoun Line, but the A-K Line would be in service as scheduled by 2012. Exhibit 36 shows the list of contingency overloads expected to occur in 2012 if only the A-K Line is in service by that time.

Exhibit 36: List of contingency overloads expected to occur in 2012 if only A-K Line is in service by 2012

Contingency	Overload	kV	Rating (MVA)	With PPT5 Loading (%)	No PPT5 Loading (%)
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598		95.1
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598		95.9

(170) Similar to the Loudoun Line case in 2011, when the proposed A-K Line is built by 2012, there is a no reliability violation in 2012. The reason is that the proposed A-K Line carries a substantial amount of the west-to-east power flows and thus reduces resulting power flows through, *inter*

contingency and loss of Black Oak–Bedington contingency) could not be solved using the full AC power flow solution. Therefore, those two contingencies were solved using DC load flow for No Possum Point Unit #5 case.

alia, the Mt. Storm–Doubs line. However, this alternative does not resolve the 2011 reliability violations since the earliest in-service date for this line is year 2012.

(171) When DVP's 750 MW Possum Point Unit #5 is unavailable,[48] Mount Storm–Doubs loading is expected to be as high as 96% (with a loss of either the Mount Storm–Greenland Gap or the Greenland Gap–Meadowbrook 500 kV line). Therefore, according to DVP's planning criteria, these loadings constitute reliability violations (albeit minor ones). However, these residual reliability violations on the Mt. Storm–Doubs line can be resolved by additional measures such as adding 640 MW Sempra units near Doubs substation. As shown in Exhibit 37, adding the Sempra units reduces the loading of the Mt. Storm–Doubs line below the 94% threshold even if Possum Point Unit #5 is unavailable.

Exhibit 37: List of contingency overloads expected to occur in 2012 if only A-K Line is in service by 2012 (no Possum Point Unit # 5 but 640 MW Sempra units added)

Contingency	Overload	kV	Rating (MVA)	No PPT5 Loading (%)	No PPT5 and Sempra On (%)
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	95.1	91.9
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	95.9	92.7

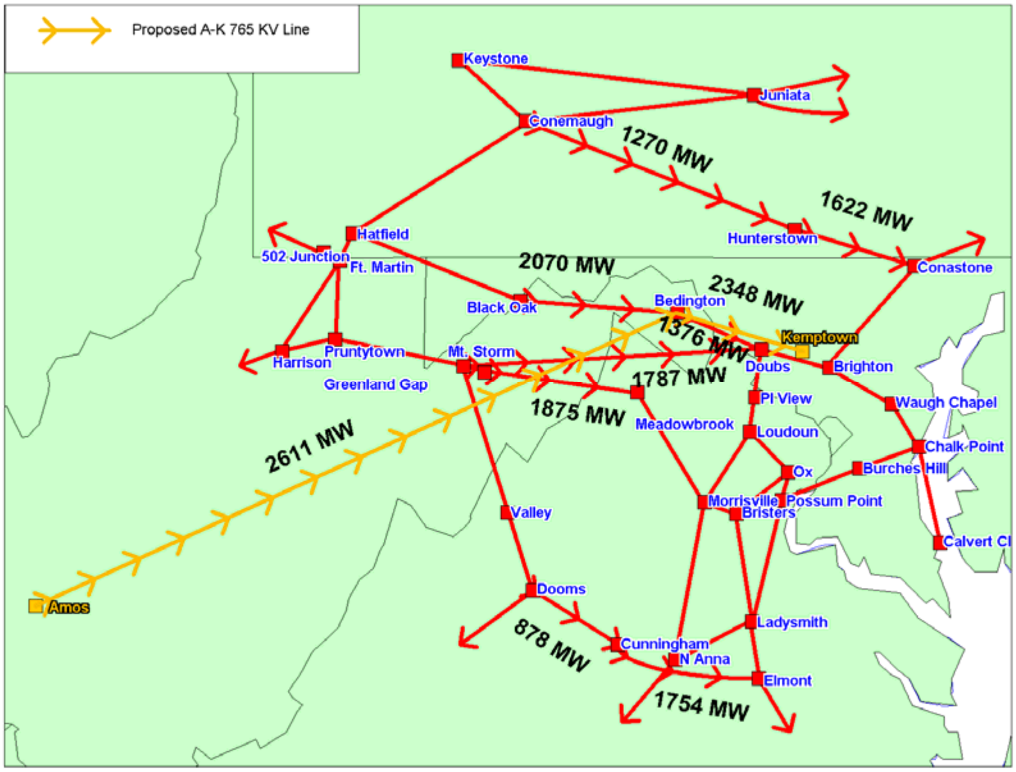
(172) By comparison, if the Loudoun Line is built by 2011, there is no major reliability violation in 2011, even if Possum Point Unit # 5 is unavailable.[49]

(173) Exhibit 38 shows the expected power flows in major transmission lines in 2012 if only the proposed Amos–Kemptown 765 kV Line is built and when DVP's 750 MW Possum Point Unit #5 is unavailable.

[48] Note that generation output of DVP's Possum Point unit #5 is modeled to be increased from 736 MW to 750 MW between years 2011 and 2012. The rated capacity of Possum Point unit is modeled as 786 MW.

[49] Note that a minor contingency overload at the Mt. Jackson–Edinburg 115 kV line for 2011 Loudoun Line with No Possum Point Unit #5 case can be resolved through minor transmission upgrades.

Exhibit 38: Expected power flows in major transmission lines in 2012 if only the proposed Amos–Kemptown 765 kV Line is built and when DVP's 750 MW Possum Point #5 is unavailable



(174) In 2012, the proposed Amos–Kemptown 765 kV line is expected to carry over 2,600 MW of west-to-east power flows. By comparison, in 2011, the proposed Loudoun Line is expected to carry about 830 MW less of west-to-east power flows than the A-K Line. By contrast, expected power flows over the existing Mt. Storm–Doubs 500 kV line are about 100 MW more than for the 2011 Loudoun Line case.

(175) Overall, the Loudoun Line case in 2011 has about 9,345 MW of expected west-to-east loading on six major backbone transmission lines, including the proposed Loudoun Line. By contrast, the A-K Line case in 2012 has about 10,490 MW of expected west-to-east loading on six major backbone transmission lines, including the proposed Amos–Kemptown 765 kV Line. As a consequence, the Loudoun Line option in 2011 has about 1,150 MW less expected west-to-east loading on six major backbone transmission lines than the Amos–Kemptown Line option in 2012.

V.1.5. FACTS option

(176) Bates White also studied the AC power flow control option. One way to control power flows is to install Flexible AC Transmission System (FACTS) controllers such as Phase Angle Regulators

(PARs) or Unified Power Flow Controllers (UPFCs). In principle, all FACTS devices control the line impedance, voltage, current, real power, and/or reactive power by either injecting voltage in series with the line (Series Controllers) or injecting current into the line (Shunt Controllers). For example, a PAR controls the AC flow by adding a perpendicular voltage vector in series with a phase to provide a variable phase angle, thereby effectively changing the impedance of the line that it controls. A UPFC performs a similar function by combining the Series and Shunt Controllers for active and reactive power flow control. Since the expected contingency overload on the Mount Storm–Doubs line in 2011 is no more than a few hundred MW, installing a FACTS device would effectively eliminate this overload by shifting flows to less-loaded lines.

(177) KEMA and DVP considered the FACTS option and concluded that it may be feasible in 2011 but infeasible by 2016.[50] However, neither KEMA nor DVP conducted actual power flow analysis to derive their conclusions. Therefore, it is worthwhile to perform the actual power flow analysis to study the impact of installing FACTS devices as an alternative to the proposed Loudoun Line.

(178) Bates White implemented a FACTS option by adding a PAR either on the Mount Storm–Doubs line or on the Pruntytown–Mount Storm line in the DVP-provided power flow cases.[51] The design characteristics of a PAR modeled in Bates White's study is as follows: maximum/minimum phase angle is plus/minus 10 degrees with step size of one degree. In addition, Bates White has assumed that sufficient voltage support would be accompanied with a PAR option so that it would not cause low voltage reliability violations.

(179) Exhibit 39 shows the impact of installing a PAR on the Mt. Storm–Doubs line in 2011.

Exhibit 39: Impact of installing a PAR on the Mt. Storm–Doubs line in 2011

Contingency	Overload	kV	Rating (MVA)	Loading (%)
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	96.2
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.5
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.6
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	100.5
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	147.7
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	143.5
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	111.2

[50] KEMA Report, at 56-58.

[51] The name of the power flow case is *S2011_2007Forecastv29nline.raw* and *S2011_2007Forecastv29nlinenppt5v29.raw* modeling 2011 system conditions with and without Possum Point Unit # 5, respectively.

(180) In 2011, when Possum Point Unit # 5 is in service, installing a PAR on the Mt. Storm–Doubs line completely resolves reliability violations on the Mt. Storm–Doubs line by diverting sufficient power flows to other lines. One drawback is that installing a PAR on the Mt. Storm–Doubs line increases contingency loading on the south, i.e., Morrisville–Bristers 500 kV line exceeds the 94% threshold. Thus, additional measures such as fine-tuning PAR design parameters on the Mt. Storm–Doubs line and/or adding additional PARs on the strategic locations would be required to sufficiently address 2011 reliability violations. Finally, reliability violations on the lower voltage branches could be resolved by conventional upgrades, which do not require a new 500 kV line.

(181) Exhibit 40 shows the impact of installing a PAR on the Pruntytown–Mt. Storm line in 2011.

Exhibit 40: Impact of installing a PAR on the Pruntytown–Mt. Storm line in 2011

Contingency	Overload	kV	Rating (MVA)	Loading (%)
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	99.5
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	97.6
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	98.7
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	98.2
BATH VALLEY	Dooms - Lexington	500	2598	94.6
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	113.1
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	99.4
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	114.3
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	109.8
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	136.3
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	134.1

(182) Installing the same PAR on the Pruntytown–Mount Storm line does not sufficiently reduce power flows to resolve 2011 contingency overloads on the Mount Storm–Doubs line. In addition, similar to the Mt. Storm–Doubs PAR case, this option increases contingency loading on the south, i.e., Dooms–Lexington 500 kV line, above the 94% threshold. This option also has reliability violations on the lower voltage branches that could be resolved by conventional upgrades.

(183) Bates White concludes that in 2011, when Possum Point Unit # 5 is in service, judicious PAR installation would resolve contingency overloads on major 500 kV lines, and the PAR option appears to be more effective on the Mt. Storm–Doubs line than on the Pruntytown–Mt. Storm line.[52]

[52] A PAR on the Pruntytown–Mt. Storm line is less effective in reducing flows on the Mt. Storm–Doubs line. A PAR on the Pruntytown–Mt. Storm line reduces flows on the Pruntytown–Mt. Storm line 356 MW more than a PAR on

(184) When Possum Point Unit # 5 becomes unavailable, contingency overloads get worse in 2011 so that additional support from transmission, generation, and/or demand response resources is required.

(185) Exhibit 41 shows the impact of installing a PAR on the Mt. Storm–Doubs line in 2011, when Possum Point Unit # 5 is unavailable.

Exhibit 41: Impact of installing a PAR on the Mt. Storm–Doubs line in 2011, when Possum Point Unit # 5 is unavailable

Contingency	Overload	kV	Rating (MVA)	Loading (%)
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	94.8
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	95.6
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	100.5
BRISTERS OX	Morrisville - Loudoun	500	2598	97.8
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598	95.0
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	102.3
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	102.6
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	124.0
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	122.3
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	150.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	115.4
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	98.1
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	154.3

(186) Now, contingency loadings on the Mt. Storm–Doubs line are slightly over the 94% threshold, with a loss of either the Mt. Storm–Greenland Gap or the Greenland Gap–Meadowbrook 500 kV lines. In addition, contingency overloads on the south, such as Morrisville–Bristers, Bristers–Ox, and the Morrisville–Loudoun 500 kV lines, get worse. This is due to a loss of Possum Point Unit # 5 unit and redirected flow from the north that otherwise would not flow to the south in the absence of a PAR on the Mt. Strom–Doubs line.

(187) Exhibit 42 shows the impact of installing a PAR on the Pruntytown-Mt. Storm line in 2011, when Possum Point Unit # 5 is unavailable.

the Mt. Storm–Doubs line does; but a PAR on the Pruntytown–Mt. Storm line only reduces flows on the Mt. Storm–Doubs line by 280 MW.

Exhibit 42: Impact of installing a PAR on the Pruntytown-Mt. Storm line in 2011, when Possum Point Unit # 5 is unavailable

Contingency	Overload	kV	Rating (MVA)	Loading (%)
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	99.7
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	102.9
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	102.1
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	100.3
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	94.8
BATH VALLEY	Dooms - Lexington	500	2598	97.4
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	102.0
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	117.9
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	115.9
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	143.2
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	94.9
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	139.2
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	114.5

(188) The PAR option appears to be less effective in relieving Mt. Storm–Doubs contingency overloads on the Pruntytown–Mt. Storm line rather than on the Mt. Storm–Doubs line. With a PAR on the Pruntytown–Mt. Storm line, there are four contingency loadings of about 100% on the Mt. Storm–Doubs line, with a loss of the (1) Black Oak–Bedington, (2) Hatfield–Black Oak, (3) Mt. Storm–Greenland Gap, or (4) Greenland Gap–Meadowbrook lines.

V.1.5.1. FACTS plus Generation Option

(189) Bates White also studied the amount of additional generation needed to make this PAR alternative feasible in terms of meeting 2011 reliability needs. The outcome of this analysis is critically dependent on both the amount and the location of added generation. More details can be found in the Generation Alternatives section of this report. Specifically, Bates White added three Sempra units (640 MW total) near the Doubs Substation and conducted the NERC N-1 Contingency Analysis. Bates White chose three Sempra units because (a) they are already modeled in DVP base case but are turned off because they were in suspension at the time of DVP base case development, (b) they are out of suspension now and thus eligible for modeling, and (c) their location (i.e., Doubs) significantly reduces power flows on the Mt. Storm–Doubs line.

(190) Exhibit 43 shows that adding three Sempra units of total 640 MW makes the Mt. Storm–Doubs PAR alternative more manageable in 2011 even when the 736 MW Possum Point Unit # 5 is unavailable.

Exhibit 43: List of contingency overloads in 2011 for the Mt. Storm–Doubs PAR and Sempra Alternative (No Possum Point Unit # 5 case)

Contingency	Overload	kV	Rating (MVA)	Loading (%)
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	100.2
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	97.7
BRISTERS OX	Morrisville - Loudoun	500	2598	94.7
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	121.2
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	119.6
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	100.9
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	149.1
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	145.8
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	111.9

(191) Note that no longer are there any Mt. Storm–Doubs reliability violations. To address reliability violations on three 500 kV lines south-east of the Mt. Storm–Doubs line, i.e., Bristers–Ox, Morrisville–Bristers, and Morrisville–Loudoun lines, Bates White added a 600 MW unit at the Loudoun substation. Bates White knows of no generators currently located near the Loudoun substation. The purpose of this study is to show that a PAR would be a feasible alternative if it were combined with additional generation resources. More details can be found in the Generation Alternatives section of this report.

(192) Exhibit 44 shows that adding three Sempra units (640 MW) and a 600 MW unit near the Loudoun substation makes the Mt. Storm–Doubs PAR alternative much more manageable in 2011, even when the 736 MW Possum Point Unit #5 is unavailable.

Exhibit 44: List of contingency overloads in 2011 for Mt. Storm–Doubs PAR plus Sempra and Loudoun Generation Alternative (No Possum Point Unit # 5 case)

Contingency	Overload	kV	Rating (MVA)	Loading (%)
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	96.2
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	94.3
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	119.0
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	117.0
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	99.3
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	109.1
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	144.8
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	141.2

(193) To address remaining reliability violations on two 500 kV lines south-east of Mt. Storm–Doubs, i.e., Bristers–Ox and Morrisville–Bristers, Bates White added an additional 400 MW unit at the Ox substation. Bates White knows of no generators currently near the Ox substation. The purpose of this study is to show that a PAR would be a feasible alternative if combined with additional generation resources. More details can be found in the Generation Alternatives section of this report.

(194) Exhibit 45 shows that adding three Sempra units totaling 640 MW, a 600 MW unit near the Loudoun substation, and another 400 MW unit near the Ox substation makes the Mt. Storm–Doubs PAR alternative essentially feasible in 2011, even if the 736 MW Possum Point Unit #5 is unavailable. The total generation MW added is about 1,650 MW.

Exhibit 45: List of contingency overloads in 2011 for the Mt. Storm–Doubs PAR, plus 640 MW Sempra Units, plus a 600 MW Loudoun Unit, plus a 400 MW Ox Unit Alternative (No Possum Point Unit # 5 case)

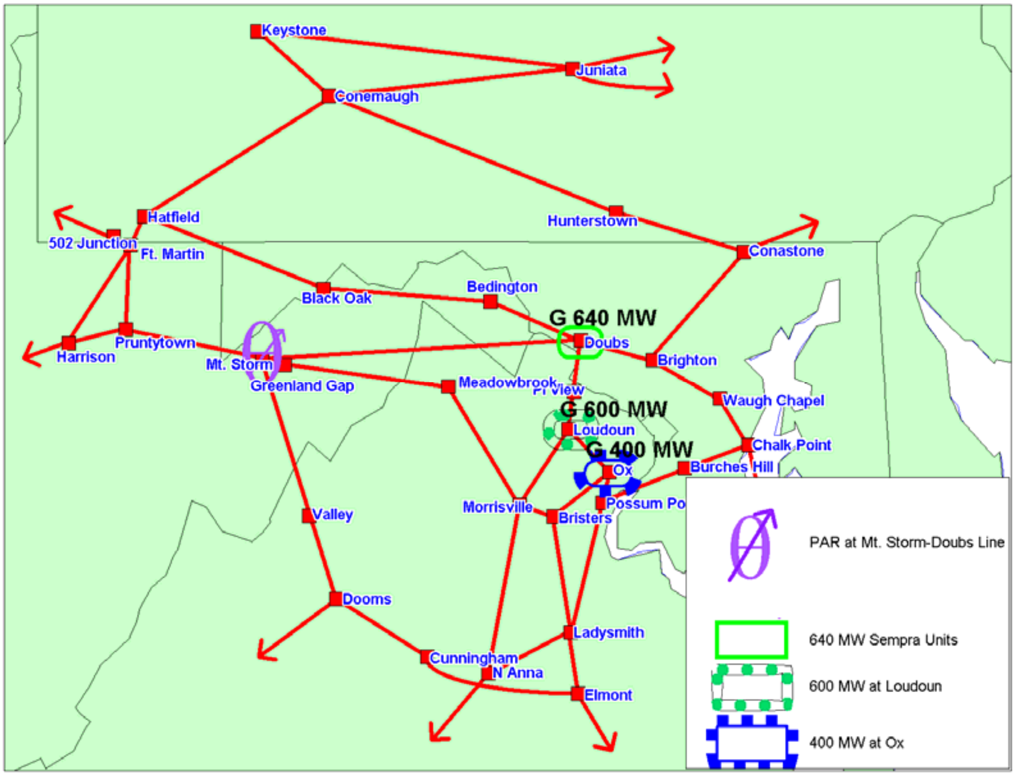
Contingency	Overload	kV	Rating (MVA)	Loading (%)
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	98.0
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	115.8
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	117.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	106.8
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	142.3
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	139.0

(195) Note that there is no reliability violation on any of the 500 kV lines. Contingency overloading on lower voltage branches can be fixed with conventional transmission upgrades. PJM RTEP contains such examples.

(196) Bates White concludes that the listed combinations of generations and a PAR would be a feasible alternative to address 2011 reliability violations. One drawback is that as time goes on, one would need to continuously add additional combinations of generation and transmission solutions to reliably serve the expected load growth.

(197) Exhibit 46 illustrates the Mt. Storm–Doubs PAR option in conjunction with 640 MW Sempra units near the Doubs substation, a 600 MW unit near the Loudoun substation, and a 400 MW unit near the Ox substation as a feasible combined transmission and generation alternative to the proposed Loudoun Line in 2011.

Exhibit 46: Mt. Storm–Doubs PAR option in conjunction with 640 MW Sempra units near the Doubs substation, a 600 MW unit near Loudoun substation, and a 400 MW unit near the Ox substation as a feasible combined transmission and generation alternative to the proposed Loudoun Line in 2011



V.2. Generation alternatives

V.2.1. List of potential generation additions

(198) Bates White also studied how much new generation would have to be added to avoid the need to build the proposed Loudoun Line. Several generators are likely to be in service by 2011, but these are not included in Applicants' base cases. These are as follows:

A. Sempra 640 MW facility near Doubs substation. Sempra's subsidiary, Catoctin Power, LLC, received from the Maryland Public Service Commission on April 25, 2005, a Certificate of Public Convenience and Necessity to construct and operate this combined-cycle natural gas facility at the East-Alco industrial site located near the Doubs substation, in Frederick County, Maryland. Catoctin Power filed an executed interconnection service agreement (ISA) with FERC on November 29, 2006.[53] This facility was not modeled in the power flow case

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53 See, e.g., http://www.pjm.com/planning/project-queues/isa/g51_w62_isa.pdf.

since the facility was in suspension at the time of the base case development. It entered PJM generation queue as "G51_W62" on July 31, 2001.

B. CPV Warren 600 MW plant near Meadowbrook substation. The developer, Competitive Power Ventures (CPV), has proposed to build a 600 MW combined-cycle gas-fired facility in Warren County, Virginia. This facility is expected to be in service in May 2010.[54] This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "R77" and "S52" on January 23, 2007, and May 29, 2007, respectively. According to PJM's generation queue status, this facility only completed the generation interconnection Feasibility Study.[55]

C. CPV St. Charles 640 MW plant in Maryland. The developer, Competitive Power Ventures (CPV) has proposed to build another 640 MW combined-cycle gas-fired facility in Maryland. According to CPV, work on CPV St. Charles would start in early 2009, with the plant coming on-line in 2011.[56] This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM.[57]

D. Lady Smith 340 MW plant to be built on the DVP's existing site at Ladysmith. Dominion has proposed to build two additional units providing an increase in capacity of 340 MW at its existing Ladysmith Power Station. This facility is expected to be in service in June, 2008. This facility was not modeled in the PJM power flow case because it did not have an executed ISA with PJM at the time of the base case development. It entered PJM's generation queue as "R19" on October 3, 2006. According to PJM's generation queue status, this facility recently executed interim ISA with PJM.[58]

E. Lady Smith 170 MW plant to be built on the DVP's existing site at Ladysmith. Dominion has proposed to build yet another power plant providing an additional 170 MW of capacity at its existing Ladysmith 230 kV substation. This facility is expected to be in service by the second quarter of 2009. This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "S102" on July 31, 2007. According to PJM's generation queue status, this proposed facility only completed the

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54 See, e.g., http://www.pjm.com/planning/project-queues/feas_docs/r77_fea.pdf.

55 https://www.pjm.com/planning/project-queues/queue-gen-active.jsp

56 http://www.cpv.com/pdf/pressrelease7.25.07.pdf.

57 Bates White could not identify this facility in the PJM queue. Bates White assumed that this facility would be interconnected to the Morgantown 230 kV bus (Bus Number 7054).

58 http://www.pjm.com/planning/project-queues/isa/r19_isa2.pdf.

generation interconnection Feasibility Study.[59] Dominion is proposing to add 510 MW of additional capacity at its existing site at Ladysmith with an expected in-service date before 2011.

F. Bath County 340 MW plant. Dominion has requested a 340 MW increase in capacity for Bath County Units 1, 3, 4, and 6 (85 MW each) phased over four consecutive years from spring 2006 through spring 2009. It entered PJM's generation queue as "P16" on October 19, 2005. According to PJM's generation queue status, it has already executed an ISA.[60]

G. Possum Point 600 MW facility. Dominion has proposed a 600 MW increase in capacity at its existing Possum Point substation. This facility is expected to be in service by the second quarter of 2009. This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "P08" on June 14, 2005. According to PJM's generation queue status, a System Impact Study of this proposed facility is in progress.[61]

H. Tenaska 625 MW facility. Tenaska has proposed to build a 625 MW combined-cycle generating facility in Buckingham County, Virginia. This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "P38" on December 22, 2005. According to PJM's generation queue status, this facility is currently undergoing a generation interconnection Facility Study.[62] Recently, Dominion has agreed to purchase this development project.[63] This facility is expected to be placed in service in the spring of 2011.

V.2.2. Impact of adding list of potential generation

(199) To study the impact of these generation additions, Bates White modeled the above-listed generators in sequence with the DVP-provided base case representing the 2011 "stressed" condition and conducted NERC N-1 contingency analysis.[64]

(200) Exhibit 47 shows the list of acronyms that describe the relevant 500 kV contingency conditions expected to occur in 2011 with the "stressed" system condition.

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[59] http://www.pjm.com/planning/project-queues/feas_docs/s102_fea.pdf.

[60] https://www.pjm.com/planning/project-queues/queue-gen-active.jsp.

[61] Id.

[62] https://www.pjm.com/planning/project-queues/queue-gen-active.jsp

[63] http://www.dom.com/news/elec2007/pr1205.jsp.

[64] The name of the base case file is *S2011_2007Forecastv29nlinenppt5v29.raw*.

Exhibit 47: List of acronyms that describe the relevant 500 kV contingency conditions expected to occur in 2011 with the "stressed" system condition

Contingency	Overload	kV	Rating (MVA)	Acronym
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	BH-PM
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	BB-PM
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	MM-MD
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	GM-MD
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	MG-MD
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	BH-MD
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	BB-MD
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	LM-BO
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	LM-MB
BRISTERS OX	Morrisville - Loudoun	500	2598	BO-ML

(201) Exhibit 48 shows the sequential impact of adding these generators on the 2011 contingency overloads for the relevant 500 kV transmission system when Possum Point Unit #5 is unavailable.

Exhibit 48: Sequential impact of adding generators on the contingency overloads for the relevant 500 kV transmission system (2011 No Possum Point Unit # 5 case)

Acronym	No PPT5	Sempra	CPV Warren	CPV St. Charles	Lady Smith	Bath County	Possum Point	Tenaska
BH-PM	96.4							
BB-PM	96.1							
BH-MD	105.9	101.5	101.1	98.9	97.9	99.0	97.0	97.4
BB-MD	104.4	99.8	100.9	98.5	97.8	98.7	97.0	97.3
GM-MD	111.7	107.9	105.6	102.2	100.7	101.9	99.2	99.4
MG-MD	110.9	107.1	104.8	101.4	99.9	101.2	98.4	98.6
MM-MD	95.6			94.4		94.2		
LM-MB	97.5	95.5	101.5	98.4	98.2	99.0	95.3	97.0
LM-BO	96.0		96.9		96.3	97.4		96.2
BO-ML						94.6		94.7

(202) As shown in Exhibit 48 above, adding the 640 MW Sempra facility reduces contingency overloads at issue.[65] For example, this facility resolves contingency overloads on the Pruntytown–Mt. Storm and Bristers–Ox 500 kV lines for all contingency conditions. In addition, it also

[65] In terms of modeling, Bates White reconnected the three Sempra units (two of them with 161 MW each and one of them with 318 MW) that were disconnected from the grid in the DVP-provided base cases. The corresponding bus number is 20852, which is the existing 230 kV SEMPRA bus in the AP control area.

resolves one of the five existing contingency overloads on the Mt. Storm–Doubs 500 kV line (i.e., overload with a loss of the Morrisville–Meadowbrook 500 kV line). Furthermore, it reduces the remaining four existing contingency overloads on the Mt. Storm–Doubs 500 kV line by 4% to 4.5%.

(203) Adding a 600 MW CPV Warren plant further reduces some of the Mt. Storm–Doubs contingency overloads,[66] but it significantly increases contingency overloads on the Morrisville–Bristers line, and even reintroduces contingency overload on the Bristers–Ox line, which was previously resolved by adding the 640 MW Sempra facility into the base case power flow model.

(204) Adding a 640 MW CPV St. Charles plant further reduces the Mt. Storm–Doubs contingency overloads by about 2.2% to 3.3%,[67] and it also reduces the Morrisville–Bristers contingency overloads by about 3%. However, it reintroduces (albeit *de minimis*) the Mt. Storm–Doubs contingency overload with a loss of the Morrisville Meadowbrook 500 kV line, which was previously resolved by adding the 640 MW Sempra facility into the base case power flow model.

(205) Adding a 510 MW facility at the existing Lady Smith substation further reduces the Mt. Storm–Doubs contingency overloads by about 0.7% to 1.5%.[68] However, it does not reduce the Morrisville–Bristers contingency overloads, and it even reintroduces the Bristers–Ox contingency overload to the level of previous CPV Warren case.

(206) Adding 340 MW of capacity to the existing Bath County Units 1, 3, 4, and 6 (85 MW each) actually aggravates expected reliability violations on various 500 kV transmission lines.[69] In particular, it increases contingency overloads on the Mt. Storm–Doubs lines at various contingencies by about 1% compared to the previous Lady Smith case. Increasing capacity at Bath County increases power flows over the Bath County–Valley–Mt. Storm path. In this case, a 340 MW increase in Bath County capacity increases Bath County–Valley flow by about 175 MW and Valley–Mt. Storm flow by about 113 MW. This increase in flow to Mt. Storm further aggravates the Mt. Storm–Doubs contingency overloads. It also increases the Morrisville–Bristers and Bristers–Ox 500 kV lines contingency overloads by about 1% compared to the previous Lady Smith case. Furthermore, it introduces for the first time (albeit *de minimis*) the Morrisville–

[66] In terms of modeling, Bates White added 600 MW capacity at the existing Meadowbrook 500 kV bus (Bus Number 20110).

[67] In terms of modeling, Bates White added 640 MW of capacity at the existing Morgantown 230 kV bus (Bus Number 7054).

[68] In terms of modeling, Bates White added 510 MW of capacity at the existing Ladysmith 230 kV bus (Bus Number 14197).

[69] In terms of modeling, Bates White increased the capacity of existing Bath County Units 1, 3, 4, and 6 by 85 MW each. The corresponding bus numbers are 95201, 95203, 95204, and 95206.

Loudoun contingency overload with a loss of the Bristers–Ox 500 kV line, which was nonexistent in the previous cases. Lastly, this 340 MW Bath County case is the only case among those studied that has an executed ISA with PJM, and, thus, it should have been modeled in the base case anyway.

(207) Adding a 600 MW facility at the existing Possum Point substation resolves three contingency overloads that are expected to occur in the Bath County case and further reduces the Mt. Storm–Doubs contingency overloads by about 1.7% to 2.8% compared to the previous Bath County case.[70] For the Morrisville–Bristers contingency overload, it further reduces the overload by about 3.6% compared to the previous Bath County case.

(208) Lastly, adding a 625 MW development facility,[71] which was recently acquired by DVP, actually aggravates expected reliability violations on various 500 kV transmission lines. The resulting impact is very similar to the Bath County case described. For example, the facility would increase contingency overloads on the Mt. Storm–Doubs lines at various contingencies as much as 0.5% compared to the previous Possum Point case. It also increases the Morrisville–Bristers 500 kV line contingency overload by about 1.6% compared to the previous Possum Point case. Furthermore, it reintroduces the Bristers–Ox and Morrisville–Loudoun contingency violation to the previous Bath County case levels.

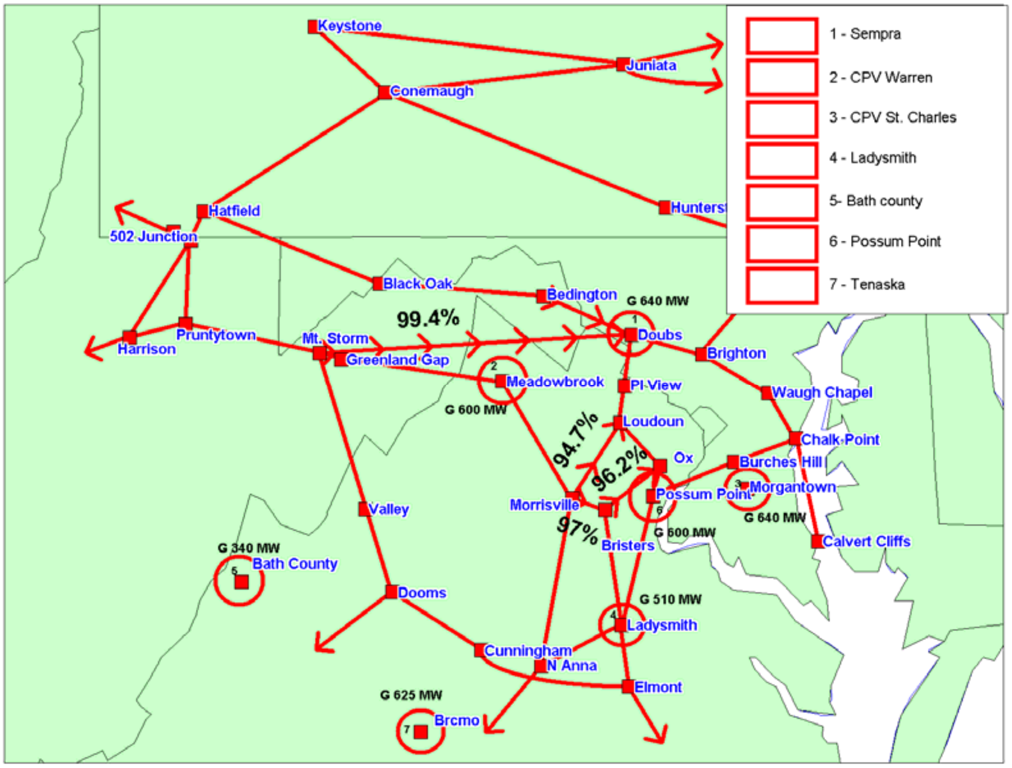
(209) In sum, without the proposed Loudoun Line (or other feasible alternatives described in this report) in service by 2011, contingency overloads at various 500 kV transmission lines are expected to occur even if 4,000 MW of capacity is added to the existing system. In addition, adding generation resources at the “wrong” location actually aggravates the severity of the expected reliability violations in 2011, as is shown by the Bath County and Tenaska cases.

(210) Exhibit 49 illustrates the amount and location of generation added in this study and the contingency overloads on various 500 kV transmission systems if no Loudoun Line is built and if Possum Point Unit # 5 is unavailable.

[70] In terms of modeling, Bates White increased the capacity of Possum Point unit #4 at bus number 95006 by 600 MW.

[71] In terms of modeling, Bates White added 625 MW of capacity at the existing Bremo 230 kV bus (Bus Number 14747).

Exhibit 49: Adding 4,000 MW of generation does not resolve the contingency overloads (2011 No Possum Point Unit # 5 case)



V.2.3. Incremental impact of adding North Anna facility

(211) Bates White has further added 1,594 MW of North Anna capacity to the Tenaska case and conducted the same contingency analysis to evaluate the impact of such a capacity addition on the remaining year 2011 reliability violations.

(212) Dominion Nuclear North Anna, LLC, has proposed to construct and interconnect a 1,594 MW nuclear generating facility located in Louisa County, Virginia. This facility is expected to be in service by the first quarter of 2015. This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "Q65" on July 14, 2006. According to PJM's generation queue status, a Facility Study of this proposed facility is in progress.[72]

[72] https://www.pjm.com/planning/project-queues/queue-gen-active.jsp.

(213) Exhibit 50 shows the impact of adding the 1,594 MW North Anna nuclear plant on the 2011 contingency overloads for the relevant 500 kV transmission system when Possum Point Unit #5 is unavailable.

Exhibit 50: Impact of adding the 1,594 MW North Anna nuclear plant on the contingency overloads for the relevant 500 kV transmission system (2011 No Possum Point Unit # 5 case)

Contingency	Overload	kV	Limit	Tenaska	North Anna
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	97.4	95.8
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	97.3	95.4
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	99.4	95.3
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	98.6	94.6
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.0	103.9
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.2	106.6
LADYSMITH POSSUM PT	Bristers - Ox	500	2598		98.1
BRISTERS OX	Morrisville - Loudoun	500	2598	94.7	105.6
BRISTERS MORRISVILLE	Morrisville - Loudoun	500	2598		100.2
LADYSMITH N ANNA	North Anna - Morrisville	500	2598		96.7
MORRISVILLE N ANNA	North Anna - Ladysmith	500	2598		106.9

(214) As shown in Exhibit 50 above, adding the 1,594 MW North Anna facility reduces expected contingency overloads at the Mt. Storm–Doubs line by approximately 2% to 4%.[73] However, this creates a new set of contingency overloads on the Bristers–Ox, Morrisville–Loudoun, North Anna–Morrisville, and North Anna–Ladysmith lines. Injecting significant power to the existing North Anna 500 kV bus will inevitably increase the flows on the North Anna–Morrisville, and North Anna–Ladysmith lines above DVP's 94% threshold. Such an increase in flows will also contribute to expected contingency overloads on the Bristers–Ox and Morrisville–Loudoun 500 kV lines. Similarly, this facility will also increase the expected contingency overloads on the Morrisville–Bristers and Bristers–Ox 500 kV lines by approximately 7% to 11%.

(215) In summary, Bates White's contingency analysis indicates that the proposed North Anna nuclear plant will significantly affect DVP's transmission system. Not only will this plant require network upgrades to reliably interconnect the proposed facility with the Dominion system, it will also not be effective in reducing the expected Mt. Storm–Doubs line contingency overloads, which is the problem the proposed Loudoun line is intended to resolve.

[73] In terms of modeling, Bates White added the capacity of proposed North Anna facility at existing North Anna 500 kV bus. The corresponding bus number is 14918.

V.2.4. Incremental impact of adding Calvert Cliffs facility

(216) Bates White also studied the impact of adding the Calvert Cliffs instead of the North Anna nuclear plant. Bates White added 1,640 MW of Calvert Cliffs capacity to the Tenaska case and conducted the same contingency analysis to evaluate the impact of such a capacity addition on the remaining year 2011 reliability violations.

(217) Constellation Generation Group, LLC, has proposed to construct and interconnect a 1,640 MW nuclear generating facility located in Calvert County, Maryland. This facility is expected to be in service by the last quarter of 2015, which is close to the North Anna plant's expected in-service date. This facility was not modeled in the PJM power flow case because it does not have an executed ISA with PJM. It entered PJM's generation queue as "Q48" on June 20, 2006. According to PJM's generation queue status, a Facility Study of this proposed facility is in progress.[74]

(218) Unlike the North Anna case, adding the 1,640 MW Calvert Cliffs nuclear facility fully resolves remaining contingency overloads.[75] In other words; the Calvert Cliffs nuclear plant is much more effective in reducing the expected contingency overloads in year 2011 than the corresponding North Anna case.

(219) In summary, Bates White's generation alternatives analysis indicates that without the proposed Loudoun Line, contingency overloads on various 500 kV lines are expected to occur as early as 2011, even if 4,000 MW of generation capacity is added to the system. Further adding about 1,600 MW from the North Anna nuclear facility does not resolve the issue. However, adding about 1,600 MW from the Calvert Cliffs nuclear facility (in addition to 4,000 MW of new capacity) successfully resolves the expected contingency overloads in 2011. This analysis shows that both the amount of capacity and the location of generation are important in resolving the contingency overloads.

V.2.5. Minimum generation capacity

(220) Since contingency overloads depend on the location of capacity injection, Bates White conducted analysis to determine whether reliability violations in 2011 can be resolved with smaller amounts of generation addition. To study this, Bates White first determined which buses are most sensitive in reducing the contingency overloads.

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[74] https://www.pjm.com/planning/project-queues/queue-gen-active.jsp.

[75] In terms of modeling, Bates White added the capacity of the proposed Calvert Cliffs nuclear facility at existing Calvert Cliffs 500 kV bus. The corresponding bus number is 20.

(221) The results of the Bates White study can be summarized as follows:

- The most beneficial generators in terms of reducing Mt. Storm–Doubs line flows are the Sempra facility in the AP control area and the Dickerson facility in the PEPCO control area
- The least beneficial generators in terms of increasing Mt. Storm–Doubs line flows are the Mt. Storm and Bath County facilities in the DVP control area
- Adding generators (or reducing loads) at the Doubs and Bedington buses in the AP control area is one of the most beneficial measures in terms of reducing Mt. Storm–Doubs line flows

(222) Taking these findings into consideration, Bates White estimated the *minimum* amount of additional capacity in the Sempra and Doubs buses in AP control areas that would be required to resolve reliability violations expected to occur in 2011.

(223) Exhibit 51 shows the results of the Bates White study. The minimum capacity required is about 2,800 MW.

Exhibit 51: Additional capacity in the Sempra and Doubs buses in AP control areas required to resolve reliability violations expected to occur in 2011

Acronym	Base Case (%)	Sempra (20852)	Sempra (20852)	Doubs (20105)	Doubs (20105)	Bedington (20101)	Total Capacity Added
Capacity Added (MW)		640	560	600	550	450	2800
BH-PM	96.4						
BB-PM	96.1						
BH-MD	105.9	101.5	97.8				
BB-MD	104.4	99.8	98.3				
GM-MD	111.7	107.9	104.2	99.5	95.6	93.0	
MG-MD	110.9	107.1	103.4	98.7	94.8	92.3	
MM-MD	95.6						
LM-MB	97.5	95.5					
LM-BO	96.0						

V.2.6. Summary of generation alternatives

(224) Bates White studied how much new generation would have to be added to avoid the need to build the proposed Loudoun Line. Bates White's study indicates that, without the proposed Loudoun Line (or other feasible alternatives described in this report) in service by 2011, contingency overloads at various 500 kV transmission lines are expected to occur, even if 4,000 MW of capacity is added to the existing system. These contingency overloads do not disappear even if

1,600 MW of additional nuclear generation from North Anna is added on top of 4,000 MW of additional generation resources. In addition, adding new generation resources at the "wrong" location actually aggravates the severity of the expected reliability violations in 2011. By hypothetically adding additional generation to the buses that are most effective in reducing the contingency overloads on the Mount Storm–Doubs line, Bates White also studied the *minimum* amount of new generation resources required to avoid the need of the proposed line in 2011. Bates White's study indicates that the minimum generation capacity required is about 2,800 MW.

V.3. Demand response alternatives

V.3.1. Regional Transmission Expansion Planning in the PJM RTO

(225) The PJM transmission system provides the means for delivering electricity to over 51 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. In order to ensure the continued reliability of the system, the PJM Regional Transmission Organization (RTO), in accordance with a protocol set forth in the PJM Operating Agreement (and in consultation with its stakeholders),[76] carries out a regional planning process for generation and transmission expansion that results in an annual Regional Transmission Expansion Plan (RTEP).

(226) The RTEP Protocol was initially approved by FERC in 1997, and it has been expanded and enhanced with stakeholder input through the PJM Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and the PJM Planning Committee (PC) forums. The RTEP annual planning cycle culminates in the presentation of the RTEP to the PJM Board of Managers for its approval.[77] Beginning in 2006, after considering significant stakeholder input, PJM expanded the RTEP planning horizon from 10 to 15 years.

(227) In order to accomplish PJM's goals of ensuring electric supply adequacy and the establishment and operation of robust energy and capacity markets, the RTEP process brings together four complementary types of analyses: (1) baseline reliability analyses,[78] (2) generation and transmission interconnection analyses, (3) market efficiency analyses, and (4) operational

[76] Regional Transmission Expansion Plan Protocol, Schedule 6, PJM Operating Agreement.

[77] A description of the process and the roles of each of the stakeholder committees in the RTEP process can be found in PJM's Manual 14B – Section 1.

[78] Reliability analyses include reference system voltage and thermal analysis and stability, load deliverability, and generation deliverability testing.

performance issue reviews and analyses. Each of these analyses helps identify necessary upgrades to the transmission system.

(228) The PJM RTEP planning process is intended to ensure the reliability of the regional transmission system and applies the most stringent of the applicable NERC, PJM, or local criteria in an annual planning cycle that extends and updates the transmission expansion plan with a 15-year horizon. Analysis is initiated in December prior to each annual cycle and concludes with review by the TEAC and approval by the PJM Board by the following October. A near-term reliability review (current year plus five) based on contingency analysis is carried out every year to identify system conditions that are at or nearing applicable criteria violations. Severe violations in any one deliverability area are referred for further long-term analysis of possible system enhancements. For each year between the current year plus four ("in-close" years), PJM updates and issues addenda to address changes as necessary throughout the year. Planned generation modifications or changes in transmission topology can trigger re-study and the issuance of a baseline addendum. This is referred to as a "retool" study.

(229) Each year in the RTEP process, during the establishment of the assumptions for the new annual baseline analysis updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the "in-close" range of years to validate the continued applicability of each of the "in-close" baseline analyses and resulting upgrades (including any addenda). These assumptions are provided to and reviewed by the Subregional RTEP Committee and are ultimately incorporated into the reference power flow case.

V.3.2. Recognition of demand-side resources in reliability modeling

(230) The recognition of demand response in maintaining reliability in PJM has evolved over the years. Historically, utilities have offered incentives to some of their customers in exchange for the right to manually control certain end-use loads. This demand resource capacity, controlled under bilateral capacity contracts between the utility and the customer, was referred to in PJM as Active Load Management (ALM) and was considered by the utilities in their integrated resource plans. The introduction of competitive retail markets introduced power marketers and load aggregators as promoters and developers of demand-side capacity within PJM's capacity markets. By 2002, PJM had launched pilot programs for economic energy and emergency energy and capacity with the participation of Curtailment Service Providers (CSPs). These pilots ultimately led to the integrated demand side response (DSR) program and tariff, which recognizes the contribution of demand response in sync reserves and regulation.

(231) In 2005, after extensive consultations among PJM stakeholders, PJM staff finalized its proposal for a new construct to ensure long-term supply and demand resource adequacy and competitively price delivered energy; this was called the Reliability Pricing Model or RPM. PJM filed its current capacity pricing model, the Reliability Pricing Model (RPM), with FERC in August of 2005.

(232) The RPM aligns the price paid for generation and demand-side capacity with overall system reliability requirements. According to PJM's regional transmission planning process manual, the results of locational capacity market auction(s) are used to help determine the amount and location of generation or demand-side resources to be included in the modeling of reliability. Only demand-side resources that are considered fully committed, cleared in the locational capacity market auctions, or otherwise certified are included in the modeling of reliability.

(233) The RPM auction process is comprised of one base residual auction and up to three incremental auctions per delivery year (June 1to May 31). The base residual auctions for the years 2007/2008, 2008/2009, and 2009/2010 were held by PJM in April, July, and October 2007. The base residual auction for the year 2010/2011 is scheduled to take place in January 2008.

(234) Under RPM, load response can be economic or emergency driven. Energy load reductions are voluntary (even during an emergency). Capacity demand reductions (load management) are always mandatory and delivered in response to a PJM load management emergency event. Load management actions are implemented through the LSE's under direct load control (DLC) via communications signals or upon notification to the customer by the LSE's market operations center (Firm Service Level or Guaranteed Load Drop). Load can also bid into ancillary services markets (Synchronous Reserves and Regulation).

(235) Load management capacity under RPM can be put under contract through active participation in the RPM auctions or as Interruptible Load for Reliability (ILR) without participating in the RPM auction. In order to be considered by PJM for a given delivery year, DR resources must bid by the auction date and ILR must be certified and registered three months prior to the delivery year. The nominated DR capacity (MW) can be changed during the year; ILR's nominated capacity cannot be changed.

V.3.3. Consideration of DVP demand-side capacity resources

(236) PJM staff produces an independent forecast of monthly and seasonal peak load and load management for each PJM zone, region, the RTO, and selected combinations of zones. The EDCs (DVP and Allegheny) produce their own peak demand forecasts built on long-term system peak

forecasts developed by PJM. The PJM staff and the EDCs forecast peak loads without the impact of load management, referred to as unrestricted load. The load forecasts are subsequently adjusted to account for the impact of load management prior to their use in reliability studies. This means that the load forecast in the power flows used by PJM and DVP in contingency analyses had already taken into account the impact of the then extant load management programs.

(237) As presented in DVP's Director of State Regulation David K. Koogler's direct testimony,[79] the peak load reduction attributable to DVP's tariff-based DSM programs considered in DVP's 2006 and 2007 forecasts is based on DVP's load reductions in the summer of 2006; as shown on Attachment DFK-2 of Mr. Koogler's testimony and reproduced in Exhibit 52. Of the 314 MW load reduction reported, the 39 MW corresponding to DVP's customer load participating in PJM's Economic Load Response Program were not included in the forecast adjustment due to the voluntary (and thus unpredictable) nature of the participation in the program.

Exhibit 52: Attachment DFK-2 of David Koogler's testimony

Dominion Virginia Power

Load Reductions in the Summer of 2006

Rate Schedule	Load Reduction
Variable Pricing	117 MW
Curtailable Service	8 MW
Standby Generation	37 MW
Variable Pricing/Curtailable Service	113 MW
PJM Economic Load Response Program*	39 MW
Total	314 MW
* Dominion Virginia Power customers participating in the PJM economic load response program.	

V.3.4. Current and short-term load management resources at PJM

(238) The base residual auction for the current delivery year (2007/2008) was held in April 2007; ILR registration for the same delivery year was opened until March 31.

79 Attachment DFK-2 of David K. Koogler Direct Testimony on behalf of Dominion Virginia Power Co. before the Virginia State Corporation Commission.Case No. Pue-2007-00031. Application

(239) Current load management capacity under control by PJM is a combination of customer load under pre-RPM ALM (which migrated to ILR) and customer load bid in the first Base Residual Auction (BRA). Exhibit 53 shows the currently registered ILR and DR capacity.

Exhibit 53: Registered emergency ILR and DR capacity by zone

Zone	2007-08 ILR		2007-08 DR	
	ICAP	UCAP	ICAP	UCAP
AECO	6.8	6.9		
AEP	116.5	120.3	437.6	451.9
APS	108.9	112.5		
BGE	241.6	249.3	14.7	15.2
COMED	416.2	427.2	58.4	60.3
DAY	1.9	2.0		
DOM	10.9	11.3		
DPL	26.7	27.4	31.8	32.8
DUQ	2.3	2.3		
JCPL	56.4	58.0		
METED	41.1	42.4	0.9	0.9
PECO	175.3	180.4	12.2	12.6
PENELEC	1.5	1.5		
PEPCO	23.2	23.9	5.1	5.3
PPL	245.7	253.2		
PSEG	109.6	112.8		
RECO				
	1584.6	1631.4	560.7	579.0

1) Blank cells in 2007-08 DR represent zones without registered DR for that Delivery Year

(240) Two more base residual auctions for delivery years 2008/2009 and 2009/2010 were held by PJM in July and October 2007. The BRA for the year 2010/2011 is scheduled to take place in January 2008. The DR capacities cleared at the BRAs held during 2007 are summarized in Exhibit 54. The capacities listed in the table include DR resources under control by LSEs to satisfy their own fixed-capacity resources.

Exhibit 54: Cleared DR capacity by zone

Zone	07-08 DR + FRR DR		08-09 DR + FRR DR		09-10 DR + FRR DR	
	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP
AECO			12.6	13.1	27.7	28.6
AEP	431.5	445.6	437.8	452.8	437.8	452.3
APS					69.1	71.3
BGE	14.2	14.7	268.0	277.2	282.3	291.6
COMED	60.0	62.0	56.4	58.3	76.4	79.0
DAY						
DOM						
DPL	31.4	32.4	21.4	22.1	35.9	37.1
DUQ						
JCPL			25.1	26.0	83.6	86.4
METED	1.2	1.2			4.0	4.1
PECO	11.9	12.3	53.3	55.1	114.8	118.5
PENELEC					4.0	4.1
PEPCO	4.8	5.0	30.9	32.0	62.6	64.7
PPL					5.5	5.7
PSEG			50.6	52.4	97.6	100.8
RECO					1.0	1.0
	555.0	573.2	956.1	989.0	1302.3	1345.2

1) Blank cells in 2007-08, 2008-09 and 2009-10 DR+FRR DR represent zones without cleared DR for that Delivery Year.

V.3.5. Recognition of ILR and DR in the PJM load forecast

(241) PJM issued its forecast report in January 2007. DVP's own report followed shortly thereafter. The relative timing of the RPM DR auctions (April, July, and October) with respect to the development schedule of the forecasts means that DR capacity cleared in these auctions could not be considered in the current 2007 forecast.

(242) New PJM and DVP load forecasts are currently scheduled for release in January 2008. These new peak load forecasts will be corrected for the load management capacity exercised during the summer of 2007, which included the new ILR and DR capacity secured through the first BRA.

(243) For resource and reliability planning purposes, PJM only considers registered ILR and auction cleared DR resources. The unrestricted zonal peak load forecasts are adjusted by deducting the ILR and DR contracted capacity on a one-to-one basis (in ICAP). The ILR and DR capacities are established before each planning year, so any projections for future years must make assumptions about future participation rates in RPM capacity markets and future registration rates for ILR.

(244) Since the only known registered ILR and DR capacities as of this writing (December 2007) are for delivery year 2007/2008, and the farthest cleared auction DR capacity is for delivery year 2009/2010, participation rates in ILR and RPM in 2011 and beyond have to be forecast based on this information, and assumptions must be made regarding future participation rates in these PJM programs. PJM's current approach is to assume that the capacity cleared in the farthest BRA and the currently registered ILR capacity remains constant for the rest of the planning horizon. Additionally, planned increases in capacity in load management programs reported by LSEs or aggregators, once duly vetted by PJM staff, will also be considered in adjusting future unrestricted peak load forecasts.[80]

(245) The reference base cases (power flow) available at the time of the DVP and TrAILCo Applications were based on the 2006 and 2007 peak load forecasts, both of which were developed prior to PJM's transition into RPM. Thus, the adjustments made to the forecast for load under the direct control of PJM were based on the customer load controlled under the Active Load Management program (ALM). As the capacity markets at PJM transitioned to RPM (May 31, 2007), the customer load controlled under ALM migrated to the ILR and DR designations. Most of the ALM participants chose to re-register under ILR for the 2007/2008 delivery year. Thus, to avoid double counting the ALM turned ILR load, the net incremental load management capacity attributable to the RPM auctions should be the DR capacity cleared under the BRAs.

V.3.6. Recognition of load management in retool power flow case

(246) As of December 2007, PJM and DVP are working on developing a retool power flow reference case. The retool case should span the five years from 2007 through 2012, incorporating the latest changes to the peak load forecast, and including adjustments for the results of RPM capacity market development including ILR and DR capacity.

V. 3.7 Results for 2011 power flow case with current PJM ILR plus DR numbers

(247) Bates White has studied the impact of current PJM ILR plus DR MW amounts summarized in Exhibit 55 on the 2011 expected loading on existing transmission lines using the DVP-provided 2011 power flow base case.[81]

(248) Bates White performed the following steps:

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[80] Personal communication with Paul McGlynn, Director, Transmission Planning, PJM, December 19, 2007.

[81] The file name is *S2011_2007Forecastv29nlinenppt5v29.raw*.

- Reduce the load for each zone listed in Column 1 of Exhibit 55 by the 09-10 DR + FRR DR ICAP amount shown in Column 6 of Exhibit 55
- Redispatch the entire PJM generation to rebalance the load reduction, proportional to the MW size of the generation
- Conduct NERC N-1 Reliability Study

(249) Exhibit 55 shows the results of the PJM DR study.

Exhibit 55: Results of the study of PJM DR

Contingency	Overload	kV	Rating (MVA)	No PPT5 (%)	PJM DR (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.4	95.6
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.1	95.4
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.9	104.6
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.4	103.2
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.7	110.3
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	109.5
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.6	94.3
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	94.1
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	96.2
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.7	119.0
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.6	117.2
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.4	101.0
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	96.2	96.0
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	148.2	145.2
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	144.1	141.7
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	113.7	112.7

(250) The results of the Bates White study indicate that adding more than 1,300 MW of DR does not materially affect the expected contingency overloads on major transmission lines expected to occur as early as 2011. For example, implementing over 1,300 MW of DR only reduces the contingency overloads of the Mt. Storm–Doubs line by less than 1.5%. The resulting contingency overloads of the Mt. Storm–Doubs line after the PJM DR implementation remain as high as 110.3%.

(251) Thus, Bates White concludes that PJM DR is not a feasible alternative to the proposed Loudoun Line in terms of reliably meeting the expected 2011 demand.

(252) Bates White has also studied the impact of DR on the DVP control area on the 2011 expected loading on existing transmission lines using the DVP-provided 2011 power flow base case.[82]

(253) Bates White performed the following steps:

- Reduce the load for DVP zone from 2,000 MW to 5,000 MW
- Redispatch the entire PJM generation to rebalance the load reduction, proportional to the MW size of the generation
- Conduct NERC N-1 Reliability Study

(254) Exhibit 56 shows the results of the DVP DR study on the major 500 kV lines. Bates White's study indicates that adding as much as 5,000 MW of DR on the DVP zone does not materially affect the expected contingency overloads on major 500 kV transmission lines expected to occur as early as 2011. For example, implementing 5,000 MW of DR on the DVP zone only reduces the contingency overloads of the Mt. Storm–Doubs line to the level ranging between 97% and 100%; this is still higher than the 94% threshold. In addition, DVP DR increases loadings on lines south of Mt. Storm–Doubs line, such as Bristers–Ox and Morrisville–Loudoun lines.

(255) Thus, Bates White concludes that DVP DR is not a feasible alternative to the proposed Loudoun Line in terms of reliably meeting the expected 2011 demand.

Exhibit 56: Results of the DVP DR study on the major 500 kV lines

Contingency	Overload	kV	Rating (MVA)	No PPT5 (%)	DVP 2000 MW	DVP 3000 MW	DVP 4000 MW	DVP 5000 MW
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.7	107.3	104.9	102.5	100.2
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.9	102.2	100.3	98.9	97.3
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	106.5	104.1	101.7	99.4
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.4	101.4	99.8	98.2	97.0
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	96.3	95.5	94.7	
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	98.1	99.1	100.0	101.0
LADYSMITH POSSUM PT	Bristers - Ox	500	2598					94.4
BRISTERS OX	Morrisville - Loudoun	500	2598		95.9	97.3	98.7	100.1

(256) Lastly, Bates White studied the impact of DR on the northern Virginia zone on the 2011 expected loading on existing transmission lines using the DVP-provided 2011 power flow base case.[83]

[82] The file name is *S2011_2007Forecastv29nlinenppt5v29.raw*.

(257) Bates White performed the following steps:

- Reduce the load for northern Virginia zone from 2,000 MW to 4,000 MW
- Redispatch the entire PJM generation to rebalance the load reduction, proportional to the MW size of the generation
- Conduct NERC N-1 Reliability Study

(258) Exhibit 57 shows the results of the Northern Virginia DR study on the major 500 kV lines. Bates White's study indicates that it requires more than 3,500 MW of DR on the northern Virginia zone to resolve the expected contingency overloads on major 500 kV transmission lines expected to occur as early as 2011. Thus, Bates White concludes that northern Virginia DR is not a feasible alternative to the proposed Loudoun Line in terms of reliably meeting the expected 2011 demand.

Exhibit 57: Results of the study of the impact of northern Virginia DR on the major 500 kV lines

Contingency	Overload	kV	Rating (MVA)	No PPT5 (%)	N. VA 2,000 MW	N. VA 3,000 MW	N. VA 3,500 MW	N. VA 4,000 MW
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.4				
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.1				
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.9	99.4	94.3		
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.4	98.1	95.0		
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	101.3	96.4	94.0	
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.7	102.1	97.2	94.8	
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.6				
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5				
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0				

[83] The file name is *S2011_2007Forecastv29nlinenppt5v29.raw*.

VI. Conclusions

(259) As detailed in the body of this report, Bates White assessed the reasonableness and consistency of the modeling assumptions and data inputs in the DVP, TrAILCo, and PJM power flow cases, in terms of generation, load, and transmission elements. Bates White found that these elements were consistent with the information known to the Applicants at the time of the analyses.

(260) Subsequently, Bates White conducted NERC N-1 contingency analyses to independently assess the need for the proposed Loudoun Line. Bates White found that both the Bates White and the DVP contingency analyses show major reliability violations in 2011 on the Mt. Storm–Doubs 500 kV line with the loss of any of the Mt. Storm–Greenland Gap, Black Oak–Bedington, Greenland Gap–Meadowbrook, or Hatfield–Black Oak 500 kV transmission lines. The projected overloads on the Mt. Storm–Doubs line range between 102% and 109% in Bates White's analysis. This is relatively consistent with the 102% and 105% overloads estimated in the DVP analysis.

(261) As expected, the projected contingency overloads get worse in 2016. Specifically, both the Bates White and DVP contingency analyses show major reliability violations on Mt. Storm–Doubs 500 kV line due to the loss of various 500 kV transmission lines. With such losses, the projected overloads on the Mt. Storm–Doubs line range between 94% and 126% (BW) and 105% and 135% (DVP).

(262) The Bates White study indicates that, based on the information relative to future loads, generation resources, and the transmission system available at the time of the need analysis supporting the Application, there is a need to improve the existing power system to serve the expected demand reliably in both 2011 and 2016. The Applicants' proposed Loudoun Line would fully resolve the expected reliability issues in 2011. The proposed line does not resolve the reliability issues in 2016.

(263) Considering the large investment and siting impacts of the proposed transmission line, the determination of need by the Commission should be based on the latest information available at the time of such a determination. Much has changed since the date of the Application. Among the most relevant changes are new PJM and DVP load forecasts (2008) that should reflect significant changes in the projected economic growth of the region. Of equal if not greater importance are the growing number of generators and merchant transmission projects that by virtue of having a signed interconnection service agreement (ISA) and/or having a completed Facilities Study are now considered viable by PJM and are thus included in the reference power flow case (2012

Retool Case). Also not known at the time of the Applications was the additional demand-side resource capacity captured by the three RPM Base Residual Auctions held by PJM from April to August 2007.

(264) As explained in the body of this report and in the specific findings that follow, the Amos-Kemptown line (a large west-east transmission project approved by PJM after the Applications had been filed, and scheduled to be completed by 2012) may eliminate the need for the Loudon line if other proposed generation projects come on-line as currently expected. However, as Bates White's preliminary analysis for this alternative was not based on the most comprehensive and recent load, generation, and transmission project information available, it is recommended that the Commission examine the need for the proposed line based on the more thoroughly updated 2012 retool case, which was only completed by PJM and DVP as of the last week of December 2007.

VI.1. Alternatives

(265) Bates White studied several alternatives that could resolve the major contingency overloads expected to occur as early as 2011. The results of the transmission, generation, and demand response alternatives considered are described in Section V of this report.

(266) The two alternatives that Bates White considers *feasible* are:

- Building a 502 Junction–Mt. Storm–Meadowbrook–Doubs 500 kV line (Doubs Option)
- Replacing the 500 kV Meadowbrook–Loudoun segment of the proposed line with a 230 kV double-circuit line, in concert with the assumption that three Sempra units with a total capacity of 640 MW near Doubs will be on-line by 2011 (Two 230 kV plus Sempra Option)

(267) Alternatives that Bates White examined but considers *more uncertain are*:

- Building the Amos–Kemptown 765 kV line (A-K Option); however, the earliest in-service date of AEP's A-K line is 2012, and, thus, it cannot resolve 2011 reliability violations
- Installing power flow controllers in conjunction with adding voltage support, in concert with the assumption that new generation will come on-line in strategic locations

(268) Alternatives that Bates White finds *not feasible* are:

- Terminating the line at Meadowbrook (No Loudoun Segment Option)
- Adding over 5,000 MW of generation in Virginia and Maryland

- Reducing more than 5,000 MW of demand in DVP, or over 3,500 MW in northern Virginia

(269) While certain alternatives may be technically and economically feasible, not all of them represent the same level of risk in terms of fruition. Some, such as the Amos-Kemptown line, rely on future transmission projects that, while approved by PJM, will be subject to siting and regulatory uncertainties consistent with, if not greater than, those faced by the presently proposed line, depending on the need for new transmission corridors and/or the need to cross existing conservation easements. The Meadowbrook–Doubs transmission line alternative would, in addition to being subject to the previously described siting risk, increase the reliance on Doubs as the path for even more power to flow into northern Virginia. Alternatives involving facilities located outside of Virginia are beyond the Commission's jurisdiction, and therefore outside of the Commission's direct control.

(270) A more detailed description of the above alternatives and their rationale follows.

VI.1.1. Transmission

(271) First, terminating the proposed line at Meadowbrook is not a feasible alternative. Most notably, this alternative will make contingency overloads *worse* on existing 500 kV lines that are located to the west and south of the Meadowbrook substation. This occurs because extra west-to-east power transfer through a new Mt. Storm–Meadowbrook path increases power flows on lines east and south of Meadowbrook substation.

(272) Second, changing the terminal substation of the proposed line from Loudoun to Doubs (Doubs Option) is a technically feasible alternative, although the associated routing from Meadowbrook to Doubs has not been studied. Most notably, this alternative is expected to reduce the expected loading on the Mt. Storm–Doubs line *more effectively* than the proposed Loudoun Line. This alternative runs more "parallel" to the existing Mt. Storm–Doubs line and would carry more of the power flow that would otherwise have traveled through the Mt. Storm–Doubs line. This alternative, however, would significantly increase the existing north-to-south power flow to serve the northern Virginia load, especially on the Doubs–Pleasant View–Loudoun line. This alternative would deliver more power to the Doubs substation—and thus deliver more power to Northern Virginia through the Doubs–Pleasant View–Loudoun line (north-south path)—than the proposed Loudoun option, which would provide a direct 500 kV path to northern Virginia. In short, this option makes the reliable service of northern Virginia load more reliant on Doubs. In addition, because the Doubs substation is located in Maryland, this alternative would depend on application to and approval of another State's regulatory agencies.

(273) Third, building a double-circuit 230 kV line on the Meadowbrook–Loudoun segment of the proposed Loudoun line instead of a single 500 kV line (230 kV option) *does not* fully resolve the reliability issues that are expected to occur in 2011. Compared to a single 500 kV line, two 230 kV lines would significantly reduce the expected flow on the Meadowbrook–Loudoun segment. As a result, this alternative would not sufficiently reduce the expected flow on other affected lines, not only on the Mt. Storm–Doubs line, but also on the lines south of Meadowbrook–Loudoun, such as the Morrisville–Bristers and Bristers–Ox 500 kV lines.

(274) With additional generation, the 230 kV option would be *feasible* in 2011. Specifically, Bates White's analysis indicates that adding approximately 600 MW of generation near the Doubs substation (the three proposed Sempra gas-fired units could serve that purpose) would make this 230 kV option feasible in terms of reliably meeting the expected 2011 load, even on those occasions when DVP's 736 MW Possum Point Unit #5 is unavailable (i.e., the "stressed" condition).

(275) Fourth, Bates White studied the Amos–Kemptown 765 kV line option (A-K 765 kV line option). AEP and AP have proposed to build a new 765 kV line starting from the John Amos substation near St. Albans, West Virginia, ending at the Bedington substation. From the Bedington substation, a double-circuit 500 kV line would be extended to a new substation in Kemptown, Maryland, near the existing Doubs–Brighton and Brighton–Conastone 500 kV lines. The proposed in-service date for this facility is June 1, 2012, and the expected cost is approximately $1.8 billion. Since the planned in-service date of the proposed A-K 765 kV line is no earlier than 2012, this transmission alternative cannot resolve reliability violations expected to occur in 2011.

(276) If the proposed A-K 765 kV line is built by 2012, there is no reliability violation in 2012 even if the proposed Loudoun Line is not built. The proposed A-K 765 kV line carries a substantial amount of the west-to-east power flows and thus reduces resulting power flows through other west-to-east paths, inter alia, the Mt. Storm–Doubs line. However, this alternative does not resolve the 2011 reliability violations since the earliest in-service date for this line is year 2012. Further, as transmission projects are often delayed due to siting issues, this in-service date could be delayed by one or more years.

(277) Fifth, Bates White studied the AC power flow control option. One way to control power flows is to install active flow control devices such as a Phase Angle Regulator (PAR). A PAR controls the AC flow by changing the effective impedance of the line that it controls. The PAR option should be implemented judiciously since it diverts flows into other lines; and these lines may overload as

a result of active PAR control. Also, a PAR will introduce additional impedance to the existing system, necessitating additional voltage support.

(278) The Bates White study indicates that judicious PAR installation would resolve contingency overloads on major 500 kV lines, and the PAR option appears to be more effective if the PAR is installed on the Mt. Storm–Doubs line as opposed to the Pruntytown–Mt. Storm line. However, if DVP's Possum Point Unit #5 is unavailable (the "stressed" condition), the PAR option alone cannot resolve the contingency overloads on major 500 kV lines that are expected to occur as early as 2011, and thus additional support from transmission, generation, and/or demand response resources is required to meet the expected load growth in 2011 reliably.

VI.1.2. Generation

(279) Bates White studied how much new generation is needed to avoid the proposed Loudoun Line. The Bates White study indicates that, without the proposed Loudoun Line (or other feasible alternatives described in this report) in service by 2011, contingency overloads at various 500 kV transmission lines are expected to occur even if as much as 4,000 MW of capacity is added to the existing system. These contingency overloads do not disappear even if 1,600 MW of new nuclear generation at North Anna is added to the 4,000 MW of new generation resources. Further, adding new generation resources at the "wrong" location actually aggravates the severity of the expected reliability violations in 2011. Bates White has also studied the *minimum* amount of optimally located new generation resources required to avoid the need of the proposed line in 2011 and concludes that the minimum generation capacity required is approximately 2,800 MW.

VI.1.3. Demand-side management

(280) Bates White's study of demand-side alternatives to the Loudoun line first had to recast the Applicants' analysis of how much northern Virginia load would have to be reduced so as to avoid the need for the line. Clearly, the relatively small contribution (8%) of the northern Virginia load to the Mt. Storm-Doubs overload makes any peak load reduction in the area, even a significant one, have little impact on its elimination. As the demand growth in eastern PJM contributes most to the need for the proposed line, Bates White looked at the potential impact of PJM's load management programs in the region to reduce the need for the line. The three Base Residual Auctions for demand-side capacity held this year by PJM have shown great promise in securing load management as a resource to manage reliability in the region.

(281) Bates White's study did not explore the potential for energy-efficiency (EE) programs for two reasons. First, it is not clear at this point how PJM or DVP would consider the contribution of EE

in maintaining reliability. Further, while EE programs can often be approved and launched in a very short time, it can take years of slow progress to obtain meaningful levels of participation. This ramp-up time was considered by Bates White as limiting the feasibility of EE programs to defer the 2011 need for the proposed line.

(282) As presented in the analysis of the PJM demand-side capacity auction results, there are now well over 2,000 MW of load under direct PJM control; a significant share of that capacity is in eastern PJM. While little or none of that capacity is located in Dominion Virginia Power's territory, DVP has recently launched four demand response/load management pilot programs, some scheduled to run through 2014. Existing load under DVP control is already internalized in the DVP load forecast as discussed in the main body of this report.

(283) While Bates White's study of load management in combination with other alternatives, based on the 2012 retool reference case, is ongoing at the time of this writing (December 2007), Bates White analyzed the effect of the latest PJM load management capacity on the mitigation of the 2011 reliability violations. Bates White's preliminary analysis indicates that the impact of the load management capacity in eastern PJM at the level cleared by the RPM auctions is relatively small in terms of alleviating the 2011 reliability violations. This is likely the result of higher-cost eastern PJM generation resources backing down as the peak demand is decreased by load management, while the lower cost western PJM generation continues to drive the west-to-east flow across the overloaded Mt. Storm-Doubs line. Bates White's analysis indicates that in order to eliminate the 2011 violations, it would be necessary to have over 5,000 MW of load under control across DVP, or over 3,000 MW in northern Virginia. The latter is an impossibility given the approximately 6,800 MW peak demand projected for 2011 for that area.

VII. Appendix

VII.1. Comparison of DC versus full AC load flow contingency study results

(284) Since 2016 system conditions are very uncertain, and there are known problems of significant reactive power deficiency in the PJM region, DVP used DC load flow in order to perform its 2016 contingency analyses. Therefore, unless otherwise specified, Bates White also used DC approximation in conducting the 2016 contingency analyses.

(285) There are several ways to specify how to handle changes in reactive power during the contingency calculations. The lossless DC methods are based on the real power MW in the

system, thus an assumption needs to be made about the reaction of the MVAR flows during the linear calculations. The choices are:

A. Ignoring reactive power. Reactive power is completely ignored. This results in the MW flow only being compared to the limits of the elements in the system. It is important to recognize this fact, as branch and transformer limits are usually given in complex power (MVA) ratings. Ignoring reactive power results in comparing active power flow (MW) to total complex power limits (MVA).

B. Assuming constant voltage magnitude. One way to include reactive power in the linearized DC results is to assume the voltage magnitudes remain constant during the linearized DC contingency analysis. The MW flows are determined from the linearized calculations, and the MVAR flows are calculated from the resulting flows and constant voltage magnitudes. One will still receive an approximate complex power flow on each element (MVA) that can then be directly compared to the complex power limit of the element.

C. Assuming reactive power does not change. Another way to include reactive power in the linearized DC results is to assume the reactive power magnitudes remain constant during the linearized analysis. The MW flows are determined from the linearized calculations, and the complex power flow of each element can be approximated using the calculated MW flows and the assumed constant MVAR flows from the base case. This allows the approximate complex flow on each element to be compared to the complex power limit of the element.

(286) Bates White has used the second approach (i.e., assuming constant voltage magnitude) in conducting DC load flow contingency analysis for 2016 system conditions.

(287) Exhibit 58 and Exhibit 59 compare the NERC N-1 reliability study results performed with full AC and DC load flow for 2011 contingency overloads for 500 kV transmission lines with and without Possum Point Unit # 5, respectively.

Exhibit 58: Comparison of NERC N-1 reliability study results performed with full AC and DC load flow for 2011 contingency overloads for 500 kV transmission lines when DVP's Possum Point Unit #5 is in service

Contingency	Overload	kV	Rating (MVA)	Full AC (%)	DC (%)	Full AC - DC (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.7	97.5	-0.8
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.5	97.2	-0.6
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	108.1	109.7	-1.6
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	101.9	105.4	-3.5
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	108.8	110.2	-1.4
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	103.2	105.7	-2.5
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	115.4	119.1	-3.7
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	99.1	100.1	-1.0
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	117.0	119.9	-2.8
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	109.0	111.7	-2.8
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	141.4	148.4	-7.0
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	137.8	146.9	-9.1

Exhibit 59: Comparison of NERC N-1 reliability study results performed with full AC and DC load flow for 2011 contingency overloads for 500 kV transmission lines when DVP's Possum Point Unit #5 is unavailable

Contingency	Overload	kV	Rating (MVA)	Full AC (%)	DC (%)	AC - DC (%)
BLACK OAK-HATFIELD & BLACK OAK TX	Pruntytown - Mount Storm	500	3502	96.4	97.0	-0.6
BEDINGTON BLACK_OAK	Pruntytown - Mount Storm	500	3502	96.1	96.7	-0.5
BLACK OAK-HATFIELD & BLACK OAK TX	Mount Storm - Doubs	500	2598	105.9	108.5	-2.6
BEDINGTON BLACK_OAK	Mount Storm - Doubs	500	2598	104.4	108.2	-3.8
GREENLANDGAP MEADOWBROOK	Mount Storm - Doubs	500	2598	111.7	113.4	-1.7
MT STORM GREENLANDGAP	Mount Storm - Doubs	500	2598	110.9	112.8	-1.9
MORRISVILLE MEADOWBROOK	Mount Storm - Doubs	500	2598	95.6	97.0	-1.5
CUNNINGHAM-ELMONT & ELMONT TX	Mount Storm - Doubs	500	2598		94.9	
DOUBS BEDINGTON	Mount Storm - Doubs	500	2598		95.1	
LOUDOUN MORRISVILLE	Bristers - Ox	500	2598	96.0	95.0	1.0
LOUDOUN MORRISVILLE	Morrisville - Bristers	500	2598	97.5	96.1	1.5
GREENLANDGAP MEADOWBROOK	Endless Caverns 230-115 kV Tx	230	282.4	120.7	123.1	-2.4
MT STORM GREENLANDGAP	Endless Caverns 230-115 kV Tx	230	282.4	118.6	122.3	-3.8
CUNNINGHAM-ELMONT & ELMONT TX	Endless Caverns 230-115 kV Tx	230	282.4	101.4	103.0	-1.6
DOOMS CUNNINGHAM	Mount Jackson - Edinburg	115	152	96.2	97.2	-0.9
GREENLANDGAP MEADOWBROOK	Mount Jackson - Edinburg	115	152	148.2	154.1	-5.9
MT STORM GREENLANDGAP	Mount Jackson - Edinburg	115	152	144.1	152.7	-8.6
CUNNINGHAM-ELMONT & ELMONT TX	Mount Jackson - Edinburg	115	152	113.7	116.9	-3.2

Annex C: Addendum Acknowledgement

	Department of Administration Purchasing Division 2019 Washington Street East Post Office Box 50130 Charleston, WV 25305-0130	State of West Virginia Centralized Expression of Interest Service - Prof

Proc Folder:	1954879	**Reason for Modification:** Addendum No. 01
Doc Description:	Engineering Review of MARL Project	
Proc Type:	Central Contract - Fixed Amt	

Date Issued	Solicitation Closes	Solicitation No	Version
2026-04-30	2026-05-06 13:30	CEOI 0926 PSC2600000002	2

BID RECEIVING LOCATION

BID CLERK
DEPARTMENT OF ADMINISTRATION
PURCHASING DIVISION
2019 WASHINGTON ST E
CHARLESTON WV 25305
US

VENDOR

Vendor Customer Code:

Vendor Name :

Address :

Street :

City :

State : **Country :** **Zip :**

Principal Contact :

Vendor Contact Phone: **Extension:**

FOR INFORMATION CONTACT THE BUYER
Larry D McDonnell
304-558-2063
larry.d.mcdonnell@wv.gov

Vendor Signature X **FEIN#** 52-2183096 **DATE** 5/6/26

All offers subject to all terms and conditions contained in this solicitation

ADDITIONAL INFORMATION
Addendum No. 01 To extend bid opening from May 05, 2026, to May 06, 2026. The bid opening time still remains at 1:30PM EST/EDT. No other changes

INVOICE TO	SHIP TO
PUBLIC SERVICE COMMISSION 201 BROOKS ST CHARLESTON WV 25301 US	PUBLIC SERVICE COMMISSION 201 BROOKS ST CHARLESTON WV 25301 US

Line	Comm Ln Desc	Qty	Unit Issue
1	Review - Mid-Atlantic Resiliency Link (MARL)		

Comm Code	Manufacturer	Specification	Model #
81100000			

Extended Description:
Please see attached documentation for further details.

SCHEDULE OF EVENTS		
Line	**Event**	**Event Date**

SOLICITATION NUMBER: CEOI PSC26*02
Addendum Number: 01

The purpose of this addendum is to modify the solicitation identified as ("Solicitation") to reflect the change(s) identified and described below.

Applicable Addendum Category:

[X] Modify bid opening date and time

[ ] Modify specifications of product or service being sought

[ ] Attachment of vendor questions and responses

[ ] Attachment of pre-bid sign-in sheet

[ ] Correction of error

[ ] Other

Description of Modification to Solicitation:

To extend bid opening from May 05, 2026, to May 06, 2026.

The bid opening time still remains at 1:30PM EST/EDT.

No other changes

Additional Documentation: Documentation related to this Addendum (if any) has been included herewith as Attachment A and is specifically incorporated herein by reference.

Terms and Conditions:

1. All provisions of the Solicitation and other addenda not modified herein shall remain in full force and effect.

2. Vendor should acknowledge receipt of all addenda issued for this Solicitation by completing an Addendum Acknowledgment, a copy of which is included herewith. Failure to acknowledge addenda may result in bid disqualification. The addendum acknowledgement should be submitted with the bid to expedite document processing.

ADDENDUM ACKNOWLEDGEMENT FORM
SOLICITATION NO.: CEOI PSC26*02

Instructions: Please acknowledge receipt of all addenda issued with this solicitation by completing this addendum acknowledgment form. Check the box next to each addendum received and sign below. Failure to acknowledge addenda may result in bid disqualification.

Acknowledgment: I hereby acknowledge receipt of the following addenda and have made the necessary revisions to my proposal, plans and/or specification, etc.

Addendum Numbers Received:
(Check the box next to each addendum received)

[✓]	Addendum No. 1	[ ]	Addendum No. 6
[ ]	Addendum No. 2	[ ]	Addendum No. 7
[ ]	Addendum No. 3	[ ]	Addendum No. 8
[ ]	Addendum No. 4	[ ]	Addendum No. 9
[ ]	Addendum No. 5	[ ]	Addendum No. 10

I understand that failure to confirm the receipt of addenda may be cause for rejection of this bid. I further understand that that any verbal representation made or assumed to be made during any oral discussion held between Vendor's representatives and any state personnel is not binding. Only the information issued in writing and added to the specifications by an official addendum is binding.

Bates White Economic Consulting
Company

Authorized Signature

5/6/26
Date

NOTE: This addendum acknowledgement should be submitted with the bid to expedite document processing.